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COMPLETED

NUREG-1057
Supplement No. 5

Safety Evaluation Report
related to the operation of Beaver Valley Power Station Unit 2

ORIGINAL

Docket No. 50-412

Duquesne Light Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1987

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NUREG-1057
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Safety Evaluation Report
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Duquesne Light Company, et al.

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Office of Nuclear Reactor Regulation

May 1987

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II

ABSTRACT

This report, Supplement No. 5 to the Safety Evaluation Report for the application filed by the Duquesne Light Company et al. (the applicant) for a license to operate the Beaver Valley Power Station, Unit 2 (Docket No. 50-412), has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status of certain items that had not been resolved when the Safety Evaluation Report and its Supplements 1, 2, 3, and 4 were published.

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

The Nuclear Regulatory Commission (NRC) Safety Evaluation Report (NUREG-1057) (SER) on the application of the Duquesne Light Company (DLC or the applicant) for a license to operate the Beaver Valley Power Station, Unit 2, was issued in October 1985. Supplements 1, 2, 3, and 4 were issued in May, August, and November, of 1986 and March of 1987, respectively. This is the fifth supplement to the SER.

The purpose of this fifth Supplemental Safety Evaluation Report (SSER 5) is to revise the SER by providing the results of the staff's review of new information subsequently submitted by the applicant. The information provided in letters referenced in this SSER must be acceptably documented in amendments to the Beaver Valley Unit 2 Final Safety Analysis Report (FSAR) by the applicant.

Each section or appendix of this SSER is designated and titled so that it corresponds to the section or appendix of the SER that has been affected by the staff's additional evaluation. Except where specifically noted, the SSER does not replace the corresponding SER section or appendix. Appendix A is a continuation of the chronology of events, including correspondence, leading to the publication of this SSER. Appendix E is a list of the principal contributors to this SSER. Appendix H, which first appeared in SSER 1, is expanded by additional material. Appendix P, "Errata," corrects errors in the SER and in SSER 1 through 4. No changes were made to Appendices B, C, D, F, G, I, J, K, L, M, N, O, and Q.

Tables 1.2, 1.3, 1.4, and 1.5, all corresponding to tables of the same numbers in the SER and previous supplements, provide summaries of the status of open, backfit, confirmatory, and license condition issues, respectively. If the status of an issue has changed since issuance of the SER, details of the change are documented in this supplement.

Action items that resulted from the Three Mile Island Unit 2 (TMI-2) accident have been addressed in the SER; Table 1.1 of the SER provided cross-references of various items to sections in the SER. TMI-2 action items that were not fully closed out in the SER have been identified as open or confirmatory issues in the SER or its supplements. Closeout status of open or confirmatory TMI-2 issues may be obtained by reviewing Tables 1.2 and 1.4 of this supplement.

Action items that resulted from the Salem anticipated-transient-without-scram (ATWS) (NUREG-1000) event have been addressed in various SER supplements. Close-out status of these items is presented in Section 15.8 of this supplement. Those actions that have not been completed by the time of operating license issuance will be carried as operating reactor actions.

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The NRC Project Manager is Peter S. Tam. He was assisted by Messers. Jaime Guillen, Roger Pedersen, and Frank Orr, Project Engineers. Mr. Tam may be contacted by calling (301) 492-4837 or by writing to the following address:

Division of Reactor Projects I/II
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

The next supplement (SSER 6) is expected to be issued about July 1987.

Table 1.2 Open issues

Issue	Status	SER section
(1) Preservice/inservice testing program		
(a) PST	Closed in SSER 3	3.9.6
(b) IST	Closed in SSER 5	3.9.6
(2) Pump and valve leak testing	Closed in SSER 3	3.9.6
(3) Inadequate core cooling instrumentation (Item II.F.2 of NUREG-0737)	Closed in SSER 2	4.4.7
(4) Preservice/inservice inspection program		
(a) PSI	Closed in SSER 5	5.2.4.3, 6.6.3
(b) ISI	Closed in SSER 5	5.2.4.3 6.6.3
(5) Safe and alternate shutdown	Closed in SSER 5	9.5.1
(6) Management and organization	Closed in SSER 5	3.1, 13.4, 13.5.1
(7) Cross-training program	Closed in SSER 1	13.2.1.2
(8) Emergency preparedness plan	Closed in SSER 5	13.3.3
(9) Initial test program	Closed in SSER 3	14
(10) Control room design review	Closed in SSER 5	18.1
(11) Safety parameter display system	Closed in SSER 5	18.2

Table 1.3 Backfit issues

Issue	Status	SER section
(1) Snow and ice load	C	2.3.1
(2) Underestimation of atmospheric dispersion conditions (χ/Q) at exclusion area boundary and consequences of radioactive release	C	2.3.4, 15.4.8
(3) Potential for flooding from probable maximum precipitation and Peggs Run	C	2.4.2, 2.4.10
(4) Steam generator level control and protection	C2	7.3.3.12
(5) Motor-operated accumulator isolation valve	C	8.3.1.12
(6) Spent fuel pool maximum heat load	C	9.1.3
(7) Fire suppression in the cable spreading room	C5	9.5.1.6
(8) Class 1E power for lighting and communication systems	C	9.5.2.1
(9) Application of GDC 5 to communication systems	C	9.5.2.1
(10) Application of GDC 2 and 4 to communication systems	C	9.5.2
(11) Application of GDC 4 to lighting systems	C	9.5.3
(12) Illumination levels in excess of SRP criteria	C	9.5.3
(13) Application of RG 1.26 to areas excluded by RG 1.26	C	9.5.4-9.5.8
(14) Air dryers for emergency diesel generator	C	9.5.6
(15) Alarm for rocker arm lube oil reserve	C	9.5.7
(16) Diesel lube oil fill procedure	C	9.5.7

C - Closed in SER (October 1985).
C2 - Closed in SSER 2 (August 1986).
C5 - Closed in SSER-5 (May 1987).

Table 1.4 Confirmatory issues

Issue	Status	SER section
(1) Operating procedures for continuous communication links	Closed in SSER 3	2.2.2
(2) Differential settlements of buried pipes	Closed in SSER 5	2.5.4.3.3, 2.5.4.5
(3) Internally generated missiles (outside containment)	Closed in SSER 5	3.5.1.1
(4) Internally generated missiles (inside containment)	Closed in SSER 5	3.5.1.2
(5) Turbine missiles	Closed in SSER 5	3.5.1.3
(6) Analysis of pipe-break protection outside containment	Closed in SSER 5	3.6.1
(7) FSAR drawings of break locations	Closed in SSER 5	3.6.2
(8) Results of jet impingement effects	Closed in SSER 5	3.6.2
(9) Soil-structure interaction analysis	Closed in SSER 1	3.7.3
(10) Design documentation of ASME Code components	Closed in SSER 2	3.9.3.1
(11) Item II.D.1 of NUREG-0737, pressure/relief valves	Closed in SSER 5	3.9.3.2
(12) Seismic and dynamic qualification of mechanical and electrical equipment (SQRT)	Closed in SSER 5	3.10.1
(13) Pump and valve operability assurance (PVORT)	Closed in SSER 5	3.10.2
(14) Environmental qualification of mechanical and electrical equipment (EQRT)	Closed in SSER 5	3.11
(15) Peak pellet design basis	Closed in SSER 1	4.2.1
(16) Discrepancies in the FSAR	Closed in SSER 1	4.2.2
(17) Rod bowing analysis	Closed in SSER 1	4.2.3.1(6)
(18) Fuel rod internal pressure	Closed in SSER 1	4.2.3.1(8)
(19) Predicted cladding collapse time	Closed in SSER 1	4.2.3.2(2)

Table 1.4 (Continued)

Issue	Status	SER section
(20) Use of the square-root-of-the-sum-of-the-squares method for seismic and loss-of-coolant-accident load calculation	Closed in SSER 1	4.2.3.3(4)
(21) Analysis of combined loss-of-coolant-accident and seismic loads (MULTIFLEX)	Closed in SSER 5	4.2.3.3(4)
(22) Natural circulation test	Closed in SSER 5	5.4.7.5
(23) Reactor coolant system high point vents	Closed in SSER 3	5.4.12
(24) Blowdown mass and energy release analysis methodology	Closed in SSER 5	6.2.1.3
(25) Containment sump 50% blockage assumption	Closed in SSER 5	6.2.2
(26) Design modification of automatic reactor trip using shunt coil trip attachment	Closed in SSER 5	7.2.2.3
(27) Automatic opening of service water system valves MOV113C and 113D	Closed in SSER 1	7.3.3.10
(28) IE Bulletin 80-06 concerns	Updated in SSER 5; remains open pending completion of startup tests	7.3.3.13
(29) NUREG-0737, Item II.F.1, accident monitoring instrumentation positions	Closed in SSER 1	7.5.2.2
(30) Bypass and inoperative status panel	Closed in SSER 5	7.5.2.4.
(31) Revision of the FSAR--cold leg accumulator motor-operated valve position indication	Closed in SSER 3	7.6.2.4
(32) Control system failure caused by malfunctions of common power source or instrument line	Closed in SSER 5	7.7.2.3
(33) Confirmatory site visit		
(a) Independence of offsite power between the switchyard and Class 1E system	Closed in SSER 1	8.2.2.3
(b) Confirmation of the protective bypass	Closed in SSER 1	8.3.1.2

Table 1.4 (Continued)

Issue	Status	SER section
(33) Confirmatory site visit (Continued)		
(c) Verification of DG start and load bypass	Closed in SSER 1	8.3.1.8
(d) DG load capability qualification test	Closed in SSER 1	8.3.1.9
(e) Margin qualification test	Closed in SSER 1	8.3.1.10
(f) Electrical interconnection between redundant Class 1E buses	Closed in SSER 1	8.3.1.13
(g) Verification of electrical independence between power supplies to controls in control room and remote locations	Closed in SSER 1	8.3.3.5
(34) Voltage analysis--verification of test results	Closed in SSER 5	8.3.1.1
(35) Documentation of description and analysis of compliance with GDC 50	Closed in SSER 5	8.3.3.7.1
(36) Completion of plant-specific core damage estimate procedure before fuel load	Closed in SSER 5	9.3.2.2
(37) Training program for the operation and maintenance of the diesel generators	Closed in SSER 5	9.5.4.1
(38) Vibration of instruments and controls on diesel generator	Closed in SSER 5	9.5.4.1
(39) Surveillance of lube oil level in the diesel generator rocker arm lube oil reservoir	Closed in SSER 2	9.5.7
(40) Solid waste process control program	Unchanged from SER; only need submittal before reactor heatup	11.4.2
(41) TMI Action Plan items		
(a) III.D.1.1, postaccident reactor coolant leakage outside containment	Closed in SSER 5	13.5.2
(b) II.K.1.5 and II.K.1.10, IE Bulletins on measures to mitigate small-break LOCAs and loss of feedwater	Closed in SSER 5	15.9.2 15.9.3

Table 1.4 (Continued)

Issue	Status	SER section
(41) TMI Action Plan items (continued)		
(c) II.K.3.5, automatic reactor coolant pump trip during LOCA	Closed in SSER 5	15.9.9
(d) II.K.3.17, report on ECCS outage	Closed in SSER 5	15.9.11
(e) II.K.3.31, compliance with 10 CFR 50.46	Closed in SSER 3	15.9.14
(42) Plant-specific dropped rod analysis	Closed in SSER 2	15.4.2
(43) Steam generator tube rupture	Closed in SSER 5	15.6.3
(44) Quality assurance program	Closed in SSER 1	17.4
(45) Cross-training of Unit 1 & 2 operators	Closed in SSER 4	13.2.1.1
(46) Control room isolation on high radiation signal	Closed in SSER 5	7.3.3.9
(47) Review of procedures generation package	Closed in SSER 5	13.5.2
(48) Fire protection: Amendment 12 review and site visit		
(a) Amendment 12 review	Closed in SSER 3	9.5.1
(b) Site visit	Completed on 1/30/87	9.5.1
(c) Safety-related system fire-barrier deviations	Closed in SSER 5	9.5.1
(49) Steam generator high-level trip as non-protection system	Closed in SSER 5	7.3
(50) Implementation letter of ICCI system	Closed in SSER 5	4.4.7
(51) Superheated steam in valve house due to steamline break	Closed in SSER 5	3.6.1
(52) Initial testing		
(a) Accumulator isolation valves	Closed in SSER 5	14
(b) SOV, PO, IST tests	Closed in SSER 5	14

Table 1.4 (Continued)

Issue	Status	SER section
(52) Initial testing (continued)		
(c) Plant performance after MSIV closure	Closed in SSER 5	14
(d) Steam extraction system and process computer	Closed in SSER 5	14

Table 1.5 License condition issues

License condition	Status	SER section
(1) Emergency response capability, RG 1.97, Rev. 2	Deleted in SSER 5	7.5.2.1
(2) Fire protection	Introduced in SSER 3	9.5.1
(3) Control room design review	Introduced in SSER 5	18.1
(4) Safety parameter display system	Introduced in SSER 5	18.2
(5) Fire detection and suppression	Introduced in SSER 5	9.5.1.5
(6) Main steam isolation valve testing	Introduced in SSER 5	3.10.2.3

2 SITE CHARACTERISTICS

2.5 Geology and Seismology

2.5.4 Stability of Subsurface Materials and Foundations

2.5.4.3 Stability of Foundations

2.5.4.3.3 Settlement

The staff stated in the SER that

> Because the pipelines have been buried in the soil without the instrumentation for settlement monitoring, the applicant will demonstrate the safety of buried pipes against the effects of differential settlements by an analytical evaluation of the expected differential movements of buried pipes to determine if the pipes are capable of withstanding such differential movements without exceeding the allowable pipe stresses.

The safety-related pipes to be analyzed are buried in two locations: (1) near the structures and (2) away from the structures and along the embankment slopes.

By letters dated October 23, 1986 and March 9, 1987, the applicant submitted its response to the SER requirement stated above. In its October 1986 submittal, the applicant described the method of analyzing the pipes located between structures but had not furnished the details or results of analysis. However, the applicant offered to provide any related analyses to the NRC upon request. In its March 1987 submittal, the applicant briefly described the method and results of analysis for pipes buried in the embankment slopes, but did not provide the details of analysis. The staff evaluated the details of the analysis as a long-term issue and will determine whether any further action is required of the applicant.

Confirmatory issue 2 is considered closed. Completion of the staff's review will be tracked by licensing action TAC 62885.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.2 Classification of Structures, Systems, and Components

3.2.2 System Qualification and Classifications

In a letter dated September 9, 1985, the staff approved the applicant's safety-related instrument tubing program which was documented in a letter from the applicant dated July 31, 1985. In a letter dated March 12, 1987, the applicant requested that safety-related, Class 2 process tubing inside containment be added to this program. The approved program is applicable to that portion of ASME Code Section III, Class 2 and Class 3 instrument tubing extending from the root valve to the sensing instrumentation. The root valve is the isolation valve which separates the instrument tubing from the process line. The tubing is one-half inch or less in diameter and made of stainless steel. The staff's approval was based on a detailed comparison of the applicant's program with applicable ASME code requirements. All of the components in the program are Seismic Category I and are designed, fabricated, installed, and tested using the ASME Code, Section III as guidance, except for the documentation of activities such as material certification, inspection, and final certification. These latter three activities are performed in accordance with the Duquesne Light Company Category I Quality Assurance Program for Beaver Valley, Unit 2, which is in compliance with 10 CFR 50, Appendix B.

In its March 17, 1987 letter, the applicant stated that the process tubing which will be added to the existing program will be subject to the same requirements that were outlined in the July 31, 1985 letter for safety-related instrument tubing and which was approved by the staff as discussed above. In addition, the Safety Class 2 process tubing is still considered as a part of the Reactor Coolant Pressure Boundary and will be included in the ASME Section III Stress Reconciliation Program.

On the basis of the above discussion, the staff has concluded that the applicant's program for design, fabrication, installation, testing, and inspection of safety-related process tubing for Beaver Valley, Unit 2 provides a quality level that is commensurate with that of the ASME Section III fluid systems to which it is attached, and is acceptable.

3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

See Section 3.5.1.2 which follows

3.5.1.2 Internally Generated Missiles (Inside Containment)

As stated in the SER, the applicant had committed to provide an analysis to demonstrate that adequate protection is provided for safety-related equipment

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from missiles generated by non-safety-related equipment by physical separation of safety-related and non-safety-related equipment. The applicant has evaluated and analyzed safety-related as well as non-safety-related components outside the containment, but internal to plant structures, as well as those inside the containment for potential missile sources.

The results of the applicant's detailed analysis are presented in Amendment 16 to the FSAR. As a result of the analysis, the applicant has identified that missile shields are required on some axial fans to provide missile protection for postulated missiles ejected through their inlet air flex connections. The locations of these axial fans are identified in Table 3.5-11 of Amendment 16.

On the basis of the review of the information provided in Amendment 16, the applicant's detailed analysis of internally generated missiles and the missile protection, as provided, are acceptable. The applicant has fulfilled its commitment; therefore, confirmatory issues 3 and 4 are resolved.

3.5.1.3 Turbine Missiles

In the SER, the staff opened confirmatory issue 5 to track the applicant's post-licensing actions on turbine missiles. By letter dated April 24, 1987, the applicant submitted a report providing the turbine manufacturer's calculation of missile generation probabilities. As stated in the SER, the applicant will submit, within three years of obtaining an operating license, a turbine system maintenance program based on such probabilities.

No more prelicensing action relative to turbine missiles need be performed by the applicant or the staff. Confirmatory issue 5 is closed; future actions will be tracked by licensing action TAC 62888.

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.1 Plant Design for Protection Against Postulated Failures in Fluid Systems Outside Containment

The SER indicated that the applicant committed to verify the qualification of safety-related equipment for the environmental conditions resulting from a main steam line break (MSLB) with superheated steam blowdown. This commitment was identified as confirmatory item 51 in SSER 3.

By letter dated September 20, 1986, the applicant submitted the equipment qualification report. Appendix E of that report and subsequent letters of December 19, 1986, and March 24, 1987, responded to the staff concerns described in IE Information Notice 84-90. IE Information Notice 84-90, "Main Steam Line Break Effect on Environmental Qualification for Equipment," discusses staff concerns regarding superheated steam blowdown. For certain MSLB accidents, steam generator tube bundle uncovery occurs and may result in the release of superheated steam. This will raise the temperature in the compartment containing the break, and in adjoining compartments, to levels above that previously calculated.

In the applicant's analysis, the mass and energy releases following an MSLB with superheated steam blowdown were obtained from Westinghouse report WCAP-10961 and were calculated using the Westinghouse computer code LOFTRAN. The version of LOFTRAN used includes the modification to account for heat transfer to the steam during steam generator tube bundle uncovery. This modification is described in Westinghouse Topical Report WCAP-8860, Supplement 1, which the staff found acceptable in its safety evaluation transmitted to Westinghouse by letter dated May 27, 1986.

The applicant postulated a spectrum of steam line break sizes ranging from 0.1 ft^2 to 1.0 ft^2 at different power levels (102% and 70%) for the limiting environmental condition, a break location postulated between the containment wall and the main steam isolation valve (MSIV). The affected compartments are the main steam valve house (MSVH), service building (SB), and auxiliary building (AB). The staff finds the postulated spectrum of breaks acceptable.

The Stone and Webster computer code THREED was used by the applicant to calculate the compartment environmental temperature profiles. Credit was taken for heat transfer to the surrounding concrete structures. Condensation heat transfer based on the Uchida correlation was modeled during the condensing mode, and a natural convection heat transfer coefficient was used during the subsequent time period. When the atmosphere was superheated, an 8% re-evaporization ratio was assumed. The calculated peak environmental temperature in the MSHV exceeded the qualification limit of some affected safety-related components.

Since the component temperatures generally lag behind the changes in the environmental temperature, the applicant performed a component thermal lag analysis on certain components including the cable/conduit assemblies, limit switch housings, terminal strip/junction box assemblies, and MSIV pressure transmitters. The MSIV pressure transmitters are insulated. The computer code TAP-A was used by the applicant to perform the thermal lag analysis. Four times the maximum Uchida correlation and forced convection heat transfer coefficients were used in modeling the condensing mode and saturation mode, respectively, during the steam blowdown phase. Following the blowdown phase, natural convective heat transfer was modeled. The results showed that the peak component surface temperatures for cables, terminal strips, and MSIV pressure transmitters in the MSVH were less than the corresponding qualification temperature limit throughout the entire transient. The blowdown from the break is eventually terminated by the operator action of isolating auxiliary feedwater flow to the broken loop steam generator. The peak calculated surface temperatures of the limit switches remain less than their qualification temperatures limit until the main steam isolation valves are fully isolated.

The staff has reviewed the applicant's analysis and finds that, with one exception, the assumptions and methodologies are consistent with the staff guidance in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." The exception is the method of calculating flow velocity for determining the forced convection heat transfer coefficient. The applicant's velocity was obtained from dividing the volumetric break flow by the flow area; in NUREG-0588, however, the velocity is a function of blowdown rate divided by the containment volume. The staff finds that the applicant's velocity calculation is appropriate, and therefore, acceptable for intercompartmental flow.

In order to assess the applicant's results, the staff's consultant Battelle Pacific Northwest Laboratory (PNL), performed an independent confirmatory analy-

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analysis using the modified COBRA-NC computer code. This code has previously been used by the staff for compartmental pressure/temperature response analysis. The modified code incorporates a heat transfer model and re-evaporization model (8% re-evaporization rate) in accordance with Appendix B of NUREG-0588 and provides both the compartment environmental temperature and component thermal lag analyses simultaneously. The two flow-velocity models described previously were studied separately, and the results were compared. The results of that comparison indicate that use of the NUREG-0588 velocity model is unnecessarily conservative. Therefore, for the purpose of this confirmatory analysis, the velocity model used by the applicant was used by the staff.

Two break sizes, 1.0 ft^2 and 0.9 ft^2, at a 102% power level were selected for the confirmatory analysis. PNL calculated environmental temperatures in the MSVH generally agree with those from the applicant. Although the peak environmental temperature resulting from the 1.0 ft^2 break is higher than that from the 0.9 ft^2 break, the peak component temperature resulting from the 0.9 ft^2 break is higher than that from the 1.0 ft^2 break because the transient (blowdown) occurs over a longer time period. The comparison of the staff and applicant results for the 0.9 ft^2 break is shown below. The results confirm that within the calculation time, the calculated peak component temperatures are less than their corresponding qualification limits.

Component	Calculation time (sec)	Peak calculated component temperature (°F)		Qualification temperature (°F)
		Staff (PNL)	Applicant	
Cable	1160	435	431	450
Limit switch	190	304	340	365
Terminal strip	1160	415	325	450

The calculation time of 1160 seconds for cable and terminal strip qualification corresponds to the time of operator action to isolate auxiliary feedwater flow into the broken loop steam generator. However, the calculation time of 190 seconds for limit switch qualification corresponds to the time of MSIV closure. The applicant provided justification for this difference in letters dated September 20, 1986 and March 24, 1987. This justification was based on a demonstration that the safety function provided by the limit switch is accomplished before main steam isolation occurs, and therefore, failure of the switches after that time is acceptable. As part of the justification, the applicant provided a discussion that included: (1) consideration of a spectrum of breaks, (2) the potential need for the equipment (limit switches) during the steam line break event or during subsequent recovery operations, (3) determination that failure of the equipment after performance of its safety function will not be detrimental to plant safety or mislead the operator, and (4) determination that the margin applied to the minimum operability time, when combined with additional test margin, will account for uncertainties. The staff has reviewed this justification and finds it acceptable.

In summary, on the basis of a review of the assumptions and methodoloby of the applicant's analyses for determining steam line break environments including superheated steam blowdown, and the results of the staff's independent analyses, the staff concludes that the identified equipment qualification environments are acceptable. The staff further concludes safety-related equipment will function in the indicated harsh environments. This closes confirmatory issue 51.

3.6.2 Determination of Rupture Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

In the SER, the staff reported that the applicant had committed to provide the following information:

(1) results of the evaluations of postulated pipe break analyses outside containment (confirmatory issue 6)

(2) drawings of postulated break locations showing types of breaks, structural barriers, and pipe whip restraints for all high-energy piping systems (confirmatory issue 7)

(3) results of evaluations of jet impingement effects resulting from postulated high-energy pipe breaks (confirmatory issue 8)

In Amendment 16 to the FSAR, the applicant revised FSAR Section 3.6.2 to reflect analysis and design changes which resulted from the implementation of the following staff approved programs:

(1) the April 11, 1986 final rule in the Federal Register (51 FR 12502) which amended General Design Criterion (GDC) 4 of 10 CFR 50 Appendix A to allow the "leak-before-break" technology to be applied to the reactor coolant loop piping (reference: SSER 3, Section 3.6.2)

(2) the Beaver Valley, Unit 2 WHIPJET Leak-Before-Break Program which exempted portions of the reactor coolant system, residual heat removal system, and safety injection system from consideration of pipe whip and jet impingement effects due to postulated pipe ruptures (reference: SSER 4, Section 3.6.3)

(3) the elimination of the guideline in Standard Review Plan (SRP) Section 3.6.2 to postulate 2 arbitrary intermediate pipe breaks in 11 high energy systems regardless of the stress level (reference: letter to applicant dated May 21, 1985)

In Amendment 16, the applicant submitted FSAR Figures 3.6B-12 through 3.6B-26 which contain isometric drawings of all high-energy piping systems identifying all pipe break locations, and location and type of corresponding pipe whip restraints which remain after implementation of the above three programs. In addition, information relative to the type of break (longitudinal or circumferential) and reason for postulation of the break (exceeding stress or usage factor allowables or located at a terminal end) is included on each of these drawings.

Using methodology consistent with the guidelines in SRP Section 3.6.2, the applicant has further evaluated each of the above postulated break locations for

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the dynamic effects of possible pipe whip and jet impingement on safety-related systems, components, and equipment. This evaluation resulted in a conclusion that no jet shields are required to protect against these dynamic loads.

On the basis of the above information, the staff has concluded that the applicant has provided sufficient information relative to pipe break locations and analysis of associated jet impingement and pipe whip effects to satisfy the applicable guidelines in SRP Section 3.6.2. Therefore, confirmatory issues 6, 7, and 8 are considered resolved.

In the SER, the staff reported that breaks would be postulated at those ASME Code Class 1 piping locations where the maximum stress range as calculated by equation 10 and either equation 12 or 13 in Paragraph NB-3653 of ASME Code Section III exceeds 2.4 S_m for normal and upset conditions. S_m is the allowable stress intensity of the material at design temperature as defined in ASME Code Section III, Paragraph NB-3112.4. This criterion is consistent with the guidelines in SRP Section 3.6.2.

In Table 1.9-2 of the FSAR, the applicant identified differences from standard review plans. Under SRP Section 3.6.2 in Table 1.9.2, the applicant reported that in lieu of the above criteria, breaks are postulated at locations where the maximum stress range as calculated by equation 10 and either equation 12 or 13 exceeds 3.0 S_m. The basis for this difference is as follows:

Code Class 1 piping for Beaver Valley Unit 2 has been designed to the requirements of the ASME Code, Section III (ASME III), 1971 Edition through the Winter 1972 addenda. In this version of ASME III (refer to Paragraph NB-3653), equation 10 includes a stress term for a linear throughwall temperature gradient referred to as ΔT_1. This stress term is not included in equation 10 in versions of ASME III later than the Summer of 1979 Addenda to the 1977 Edition. Applying 2.4 S_m as the threshold level in determining intermediate break locations is not considered appropriate when stress intensity ranges are calculated using the more conservative version of equation 10 specified in the ASME III edition and addenda applicable to Code Class 1 piping for Beaver Valley Unit 2. When using this more conservative version of equation 10, it is more appropriate to apply 3.0 S_m as the threshold level.

The staff has accepted this basis for deviating from SRP Section 3.6.2 criteria in its review of several recent plants whose Code Class 1 piping has been designed to versions of the ASME Code, Section III earlier than the Summer 1979 Addenda. Therefore, the staff has concluded that the pipe break criteria for Beaver Valley Unit 2 Code Class 1 piping is equally as conservative as that in SRP Section 3.6.2 and is acceptable.

3.6.3 Deterministic "Leak-Before-Break" Evaluation To Eliminate Postulated Breaks as a Design Basis for High-Energy Piping

In SSER 4, the staff provided the technical evaluation to justify issuance of a schedular exemption to the applicant, allowing delayed installation of pipe restraints on certain piping. In this supplement (SSER 5), the staff also considers the "special circumstances" under which the exemption can be granted in accordance with 10 CFR 50.12.

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Utilities have, in the past, invariably used pipe restraints and jet impingement shields to satisfy the requirement of GDC 4, which states that "structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power plant." The Commission, however, has taken steps to revise GDC 4 to allow use of advanced fracture mechanics leak-before-break technology in lieu of the traditional use of pipe whip restraints and jet impingement shields. The staff reviewed the applicant's exemption request, as documented in SSER 4, in line with the currently ongoing revision of GDC 4. In addition, the staff notes that there are significant benefits to the applicant's approach to satisfy the underlying purpose of the rule: (1) elimination of the negative safety impact that pipe restraints have on safety (see SSER 4), (2) reduction of occupational exposure associated with surveillance of the pipe restraints and jet impingement shields, (3) lowered capital investment, and (4) lowered cost of maintenance during the life of the plant.

Therefore, on the basis of the above discussion, the staff concludes that special circumstances are present. 10 CFR 50.12(a)(2)(ii) is satisfied in that the underlying purpose of GDC 4 (i.e., protection of structures, systems and components from pipe whipping and discharging fluids) can be achieved by use of leak-before-break technology without the traditional use of pipe whip restraints and jet impingement shields. 10 CFR 50.12(a)(2)(iv) is also satisfied in that elimination of the restraints and jet impingement shields also removes the negative safety impact of these pieces of equipment.

The staff concludes, on the basis of the evaluation above and in SSER 4, that a schedular exemption can be granted as part of the operating license.

3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.2 Design and Installation of Pressure Relief Devices.

The staff has not completed a detailed review of the applicant's April 10, 1987 submittal; however, based on a preliminary review, the staff found the general approach of using the EPRI test results acceptable. The applicant's submittal notes that Beaver Valley Unit 2 uses valves of the same size and model that performed satisfactorily for test sequences considered representative or that bound conditions to which the valves could be exposed.

On the basis of preliminary review, the staff concludes that the applicant's general approach to responding to this TMI item is acceptable and provides adequate assurance that the Beaver Valley Unit 2 overpressure protection system can adequately perform its intended functions. If the completion of detailed review reveals that modifications or adjustments are needed to ensure that all intended design margins are present, the staff will require that the applicant make appropriate modifications. This discussion closes confirmatory issue 11; licensing action TAC 62894 is opened to track completion of the staff's remaining actions.

3.9.6 Inservice Testing of Pumps and Valves

By letter dated April 9, 1986, the applicant submitted the Inservice Testing (IST) Program. The staff met with the applicant during February 11-12, 1987 to discuss staff concerns that resulted from its review of the IST Program. By letter dated April 15, 1987, the applicant submitted the revised IST Program, reflecting agreements made with the staff in the February 1987 meeting. The staff is reviewing the revised IST Program; since the revised program reflects agreements reached with the staff, results of the review are expected to be favorable. The submittals fulfill the purpose of open issue 1(b), which is therefore considered closed. Staff review of the IST Program is tracked by licensing action TAC 62870.

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification of Electrical and Mechanical Equipment

In SSER 4, the staff documented a number of generic and equipment-specific findings as a result of the plant site audit and inspection conducted by the Seismic Qualification Review Team (SQRT). For staff concerns needing resolution, the applicant has responded by letters dated April 16 and May 11, 1987. The staff is reviewing these submittals. On the basis of the information provided, the original staff concerns are generally resolved; however, some clarification is still needed. For example, the applicant needs to clarify the sequence of testing used in environmentally qualifying the main steam isolation valve (MSIV) control panel. There are other areas that need clarification but, on balance, the staff believes the applicant has met the regulatory requirements for seismic and dynamic qualification of the plant's mechanical and electrical equipment. The staff will review the applicant's clarifications and if necessary, will report the findings in a later SER supplement (SSER).

3.10.2 Pump and Valve Operability Assurance

3.10.2.1 Introduction

The staff performs a two-step review of each applicant's pump and valve operability assurance program to determine whether the applicant's program can ensure that all pumps and valves important to safety will operate when required for the life of the plant under normal and accident conditions. The first step is to review Section 3.9.3.2 of the applicant's Final Safety Analysis Report (FSAR).

However, this information is general in nature and lacks sufficient detail to determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. The results of the FSAR evaluation appear in Section 3.10.2 of the SER (October 1985). Any unresolved issues are resolved before or concurrent with the onsite audit; this was identified as confirmatory issue 13 in the SER.

A Pump and Valve Operability Review Team (PVORT), consisting of engineers from the NRC staff and the Idaho National Engineering Laboratory (INEL-EG&G),

conducted the second step of the review which consisted of an audit of a representative sample of installed pump and valve assemblies and their supporting qualification documents at the plant site. On the basis of the results of both the audit and the FSAR review, the PVORT determines whether the applicant's overall program conforms to the current licensing criteria presented in Section 3.10 of the Standard Review Plan (SRP). Conformance with SRP 3.10 criteria is required in order to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

The following sections include: (1) a discussion of the PVORT review process, (2) a summary of PVORT findings concerning the applicant's overall pump and valve operability assurance program, (3) a discussion of the operability issues resulting from the PVORT review, and (4) Table 3.1, which presents a summary of the audit results.

3.10.2.2 Discussion

The PVORT reviewed the pump and valve operability assurance information contained in Section 3.9.3.2 of the Beaver Valley Unit 2 FSAR and later conducted an onsite audit to determine the extent to which the pumps and valves important to safety meet the criteria listed above. The issues that resulted from the Beaver Valley FSAR evaluation appeared in the SER and were discussed at a pre-audit meeting held July 23, 1986. Several of these issues were adequately resolved by the applicant, as reported in letters dated September 23, 1986 and April 16, 1987.

The staff investigated the deep-draft pump issue during the audit. In a letter dated September 23, 1986, the applicant described the long-term operability program for deep-draft pumps. The program was verified during the site audit by reviewing documentation for the service water pump 2SWS-P21B. On the basis of the applicant's response and site verification, the deep-draft pump program should be adequate to ensure operability.

The staff requested information regarding operability of containment purge and vent valves in accordance with NUREG-0737, TMI Item II.E.4.2(6). In a letter dated April 16, 1987, the applicant responded to the request, indicating that the purge and vent valves are considered to be "active" valves only during cold shutdown and refueling operations. During normal plant operation the valves are locked closed per Beaver Valley Unit 2 Technical Specification requirements. The applicant has committed to perform leak tests and operability checks in accordance with 10 CFR 50 Appendix J. The tests are described in FSAR Section 6.2.6, Test Procedure BVT 2.1-1.47.5, and Operations Surveillance Test 2.1.10. This is an acceptable approach to meeting the requirements of NUREG-0737, Item II.E.4.2(6).

The following discussion lists the remaining SER issues as originally identified, and describes the manner by which each issue was addressed.

(1) Issue. The environmental qualification of the balance-of-plant (BOP) pump motors is not specifically mentioned in FSAR Section 3.9B.3.2.1, as compared to the BOP valve operator discussion in FSAR Section 3.9B.3.2.2, Item 5. The applicant shall amend the FSAR as needed to confirm that the operability qualification of each pump motor considered all environmental conditions over its qualified life (aging, radiation, accident environment, etc.). (See FSAR Section 3.9B.3.2.1, page 3.9.10a and SER Section 3.10.2.)

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Evaluation. In a letter dated April 16, 1987, the applicant provided a copy of the revised FSAR Section 3.9.B.3.2.1 (Amendment 16). The response indicated that motor environmental qualification was addressed in accordance with IEEE 323-1971 or IEEE 382-1972. This issue is closed.

(2) Issue. Many of the preoperational tests listed in FSAR Table 3.9B-1 are to be monitored visually rather than by calibrated instrumentation. Visual monitoring alone may not be adequate to detect subtle system responses that may differ from the responses predicted by qualification analyses. The applicant shall provide justification that the preoperational test results will validate the qualification of the systems, components, and supports. (See FSAR Section 3.9B.2, Table 3.9B-1, and SER Section 3.10.2.)

Evaluation. In a letter dated September 23, 1986, the applicant responded to this concern. The response indicated that the referenced statement was applicable to piping systems only. The applicant also referred to the responses to FSAR Questions 210.2, 210.21, 210.22, 210.23, 210.24 and 210.41 where instrumented monitoring requirements are more clearly defined. This issue is closed.

The onsite audit, which was conducted September 30 through October 2, 1986, consisted of field observations of the equipment configuration and installation for a representative sample of plant equipment. The PVORT evaluated five nuclear-steam-supply-system (NSSS) and seven balance-of-plant (BOP) pump and valve assemblies. In addition, six items (3 NSSS and 3 BOP) were inspected to verify installation status. Table 3.1 summarizes the status of each assembly that was audited and inspected. The field observations were followed by a review of the design and purchase specifications, test/analysis documents, and other documents related to equipment operability, which the applicant maintains in its central files. In addition to reviewing information concerning the selected assemblies, the PVORT also reviewed other information concerning the plant's overall equipment qualification program. Included within this broad evaluation were those programs and procedures necessary to ensure that equipment qualification issues and concerns will continue to be addressed for the life of the plant. One such program concerning the deep-draft pump issue (refer to IE Bulletin 79-15) was reviewed in depth.

The PVORT resolved all but four of the specific operability concerns that were identified at the close of the audit. These four concerns are: (1) the fuel pool cooling pump did not meet design flow rate or manufacturer's recommendations regarding vibration, (2) the MSIVs were not qualified and a design flaw had been identified, (3) the turbine-driven auxiliary feedwater pump did not have preventive maintenance identified in accordance with the turbine manufacturer's recommendations, and (4) the steam generator blowdown isolation valve load analysis did not address load effects appropriately.

In addition, at the close of the audit, the applicant was informed of eight generic issues to which the applicant must respond before fuel load. These eight issues are: (1) not all of the preservice tests required before fuel load have been completed, (2) approximately 10 to 15% of all pumps and valves important to safety are not yet installed and qualified, (3) similarity statements were not provided, (4) retrieval of qualification documents was not adequate, (5) check valve design in accordance with the Institute of Nuclear Power Operations (INPO) workshop needs to be confirmed, (6) nonconformances and dispositions did not appear to be effectively controlled, (7) FSAR drawings do not identify check valves by identification number, and (8) the FSAR does not provide a complete list of safety-related pumps and valves (BOP and NSSS). These items form the basis for the discussion presented in Section 3.10.2.3.

Following the staff's site audit, the applicant submitted letters, dated October 27, 1986; March 25, 1987, and April 16, 1987, which completely resolved all specific and generic issues except specific issue 2. The applicant needs to completely resolve specific issue 2 before achieving initial criticality, tentatively scheduled for June 30, 1987.

The PVORT believes that the applicant is dealing with the equipment qualification issue in a positive manner. During the audit, the applicant addressed all questions posed by the PVORT and committed to resolve all audit issues before fuel load or to provide adequate justification for those issues that were unresolved. Furthermore, the applicant discussed significant aspects of its overall equipment qualification program, aspects such as amplified response spectra reconciliation, equipment modification and reconciliation of original qualification reports, nozzle load verification, and review of non-safety-related equipment located in close proximity to safety-related equipment. Consequently, the PVORT believes that the continuous implementation of the applicant's overall program should provide adequate assurance that the pumps and valves important to safety will operate as required for the life of the plant.

3.10.2.3 Operability Issues

On the basis of the PVORT site audit, the staff has identified to the applicant the following four equipment-specific and eight equipment-generic issues. The status of resolution of each of these issues follows:

Specific Issues

(1) Issue. The review of the fuel pool cooling pump (Tag No. 2FNC-P21A) revealed that during pump testing the applicant had identified design flow rate and pump/motor assembly vibration readings as not being within the limits of the acceptance criteria. The vibration problem requires that the pump mounting have additional support added. The applicant shall notify the staff when (a) the installation has been modified and (b) the pump satisfactorily meets the testing of all design parameters and manufacturer's criteria.

Evaluation. In the letter dated April 16, 1987 and discussion held April 27, 1987, the applicant explained that the motor support stand has been stiffened for vibration level. The fuel pool cooling pump has been tested and accepted for operation. The test results show that the pump develops the flow rate (750 gpm) and total head (67 feet) required to support the system safety analyses (750 gpm at 40 feet). This issue is closed.

(2) Issue. The review of the main steam isolation valve (MSIV) (Tag No. 2MSS-HYV101A) found that operational problems have been identified by the applicant. Also, the SCEW sheet (environmental qualification) had not yet been completed. The applicant is considering several options to address operability of this component, including redesign or replacement. The applicant shall notify the staff when (a) a suitable modification and

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repair have been determined, (b) the necessary repairs and modifications have been completed, (c) testing has been completed, and (d) when full qualification, including environmental, has been established.

Evaluation. In the letter dated April 16, 1987, the applicant indicated that the three Crosby MSIVs will be replaced by Atwood/Morrill globe valves. The applicant will notify the staff when the valves are fully qualified, installed, and ready for operation. The staff finds the applicant's commitment to be acceptable, pending staff review of the qualification documents and confirmation of qualification. By letter dated May 15, 1987, the applicant informed the staff that installation of the MSIVs is complete, and stated that plant criticality will not occur until MISV testing has been completed. By letter dated May 11, 1987, the applicant stated that it has completed its review of the qualification documentation of the new Atwood & Morrill main steam isolation valves and has found these valves to be qualified for Beaver Valley Unit 2.

On the basis of a review of the summary information provided by the applicant, the staff finds the applicant's conclusion of qualification to be acceptable. The staff will have to review the supporting documentation in order to verify the operability qualification of the MSIVs. This issue is confirmatory.

(3) Issue. The applicant has taken exception to the vendor-recommended 5-year teardown of the emergency feedwater turbine (Tag No. 2FWE-T22). In lieu of the 5-year teardown, the applicant intends to evaluate the teardown schedule based on surveillance and trending data. The applicant shall (a) contact the vendor to compare the Beaver Valley surveillance and trending analysis programs with the vendor's recommendations and (b) reach a consensus for all maintenance activities to be performed on the turbine, including teardown.

Evaluation. The applicant has contacted the turbine vendor and has agreed to follow the vendor's 5-year maintenance program. This issue is closed.

(4) Issue. The review of the air-operated Masoneilan valve (Tag No. 2BDG-AOV100B1) identified concerns with the structural integrity analysis. The analysis of the flange connection from the operator to the bonnet utilized ASME Code equations for a pipe flange and employed the equivalent pressure technique to account for bending moments. This method does not include the effects of the direct vertical seismic load nor torsional moment. The applicant shall provide justification for not including these effects.

Seismic test reports for a 4-inch and a 3-inch valve were reviewed. Both of these reports identified amplification factors at the operator center of gravity at frequencies below 33 Hz. Amplification of the seismic loads was not included in the structural analysis. The applicant shall provide justification for not including the amplification.

Evaluation. In the letter dated October 27, 1986, the applicant determined that the effects of the vertical seismic load and amplification factor are a factor of 10 less than the torsional (bending) load applied. The effects due to the vertical seismic load were considered to be relatively insignificant. The results of the vendor's stress analysis identified a calculated

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stress of 6,000 psi compared with the 30,000-psi allowable limit. The staff finds that the applicant's explanation justifies the method of qualification. This issue is closed.

Generic Issues

(1) Issue. At the time of the audit, most construction tests had been completed. The hot functional tests were scheduled for late 1986. The applicant shall confirm that all preservice tests for safety-related pumps and valves that are required before fuel load have been completed. The applicant shall also provide a list of all preservice tests to be completed, the schedule for these tests, and the justification for any tests scheduled beyond fuel load.

Evaluation. The applicant responded to this issue in letters dated October 27, 1986 and April 16, 1987. The Initial Test Program and Pre-Operational Test Phase are described in FSAR Sections 14.2 and 14.2.1.2. The schedule for the Initial Test Program for system operability verification, preoperational test phase, and initial startup test phase is shown in FSAR Figure 14.2-3. The applicant has committed to complete all tests required for fuel load as scheduled. This issue is closed.

(2) Issue. At the time of the audit, approximately 10 to 15% of all safety-related pumps and valves had not been qualified. The applicant shall confirm that all safety-related pumps and valves are properly qualified and installed before fuel load. In addition, the applicant shall provide written confirmation that the original loads used in tests or analyses to qualify safety-related pumps and valves are not exceeded by any new loads, such as those imposed by a LOCA (hydrodynamic loads) or as-built conditions.

Evaluation. In letters dated October 27, 1986 and April 16, 1987, the applicant indicated that all pumps and valves have been qualified except for the three MSIVs (see specific issue 2). The stress reconciliation program has been completed to ensure that the actual loads imposed are below the specified design allowable loads. This issue is closed.

(3) Issue. In several instances the tested component is not the same as the installed component. However, no similarity analysis has been included in the documentation that addresses acceptability. A similarity statement (analysis of form, fit, function, manufacturing methods, materials, etc.) must be provided in all cases where the tested unit is not identical to the installed unit. The effect of these differences on component operability should be addressed. Attention should also be given to test conditions that are not identical to the expected plant conditions. The applicant shall evaluate its document files to ensure that all similarity concerns have been addressed.

Evaluation. In the letter dated October 27, 1986, the applicant made a commitment, which adequately addresses similarity analysis for two components (2 CHS-MOV 8130A and 2 IAC-MOV 130). The applicant has committed to reverify the similarity evaluations in conjunction with the finalization and turnover of these two equipment qualification packages. This is acceptable.

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In the letter dated April 16, 1987, the applicant described the basis for qualification by similarity. The Beaver Valley Unit 2 quality assurance program ensured complete and consistent content in the plant-specific qualification requirements. The equipment vendors had initial responsibility to ensure complete qualification and traceability. The applicant performed a complete review of the vendor qualification. Specific areas of review included comparison of overall and detail dimensions, similarity in design and function, use of materials, fabrication techniques, and differences between tested and installed equipment with respect to operability. Confirmation of this review is contained in the seismic review checklist.

The applicant provided similarity discussions for the quench spray pumps (2QSS-P21A, B) and the feedwater isolation valves (2FWS-RV157A, B, and C). The basis for their qualification by similarity is acceptable. This issue is closed.

(4) Issue. The audit revealed that errors were made in retrieving the appropriate qualification documents. Although the reports were eventually made available for the audit, the method of retrieval is complicated and lacks consistency. The applicant shall evaluate its document control system to (a) determine its effectiveness, (b) reduce the potential for human error, and (c) ensure that all personnel who use the document retrieval system are adequately trained.

Evaluation. In the letter dated April 16, 1987, the applicant indicated that all equipment qualification packages have been reorganized to increase the effectiveness of information retrieval and to reduce the potential for human error. For example, the seismic review checklist provides a synopsis of how the equipment was qualified and the location of pertinent information within the package. It also lists the applicable references and page numbers and provides similarity information when appropriate. This issue is closed.

(5) Issue. In a letter dated September 23, 1986, the applicant committed to evaluate any recommendations that may result from an INPO workshop held in October 1986 on check valve operability. The applicant needs to (a) describe the extent of its participation in the workshop and (b) indicate any actions (mandatory or voluntary) that will be taken at Beaver Valley to ensure check valve operability.

Evaluation. The April 16, 1987 letter indicated that the applicant's position to INPO Significant Operation Experience Report (SOER) 86-3 will closely follow the Beaver Valley Unit 1 response dated November 11, 1986. The Beaver Valley Unit 1 program includes testing of check valves, leak rate tests, back leakage, acoustic monitoring, disassembly, and inspection.

An Application Guide is being developed by the Electric Power Research Institute (EPRI) for use by INPO in conducting its audits of nuclear power plants. The applicant has committed to incorporate any requirements resulting from the Application Guide. This issue is closed.

(6) Issue. There were two instances in which the Nonconformance and Disposition (N&D) tags were not accurate, indicating that the tracking system is not as effective as it should be. The applicant shall provide evidence before fuel load that N&D 16001 and 32817 have been completed and accepted.

In addition, the applicant shall provide written confirmation before fuel load that the N&D tags and rejection tags for all safety-related pumps and valves have been satisfactorily resolved.

Evaluation. In a letter dated April 16, 1987, the applicant verified that N&D 32817 and 16001 were closed on November 10, 1986 and March 13, 1987, respectively. The applicant described various programs used to track the status and completion of all work items. In addition to quality control (QC) tracking of N&D tags, the Engineering Work Tracking System enables all levels of project management to review and assess open items with respect to system and area completion status. All N&Ds required to support fuel load will be completed by the applicant. This issue is closed.

(7) Issue. The FSAR figures do not label check valves by mark number. Since these valves are active, safety-related components, the applicant shall confirm before fuel load that all check valves are correctly identified in the FSAR figures.

Evaluation. In a letter dated April 16, 1987, the applicant stated that the check valves are presently identified on the Beaver Valley 2 design and operation drawings. This correlation between the design drawings and the FSAR figures is documented on the FSAR figures under the "notes column." This issue is closed.

(8) Issue: At the conclusion of the PVORT audit, it was apparent that a complete list of safety-related pumps and valves had not been provided in the FSAR. The applicant shall confirm before fuel load that all safety-related NSSS and BOP pumps and valves including check valves are correctly identified in the FSAR.

Evaluation. In the letter dated April 16, 1987 the applicant confirmed that all active safety-related NSSS and BOP pumps and valves, including check valves, are correctly identified in the revised FSAR tables (Amendment 13, January 1987). This issue is closed.

3.10.2.4 Summary

On the basis of the results of: (1) the component walkdown and the review of the qualification document packages, (2) the additional explanations and information provided by the applicant throughout the audit and in subsequent letters, and (3) the resolution of the SER items, the staff concludes that an appropriate pump and valve operability assurance program has been defined and substantially implemented. The continuous implementation of this overall program should provide adequate assurance that all pumps and valves important to safety will perform their safety-related functions as required for the life of the plant. With the exception of the unresolved issue identified in Section 3.10.2.3 (i.e., MSIVs), the staff concludes that Beaver Valley Unit 2 has qualified those pumps and valves important to safety so as to meet the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

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3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in General Design Criteria (GDC) 1 and 4 of Appendix A to 10 CFR 50 and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been stated in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323; and various NRC regulatory guides (RGs) and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews.

The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term operating license (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for Beaver Valley Unit 2 may be qualified according to the criteria specified in Category II of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B to 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated June 22 and November 1, 1984; May 23, October 15, November 20, December 3, 1986; December 19, 1986; March 4, March 24, and March 27, 1987 to supplement the information in FSAR Section 3.11.

The staff has reviewed the adequacy of the Beaver Valley Unit 2 environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and the program for safety-related mechanical equipment. The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

3.11.3 Completeness of the Environmental Qualification Program

The staff evaluation included an onsite examination of some equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria in SRP Section 3.11, Revision 2, and in Category II of NUREG-0588, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff audited the applicant's qualification documentation and installed electrical equipment on November 18, 19 and 20, 1986. The audit consisted of a review of 10 files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4 of this supplement.

3.11.3.1 Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule:

(1) safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(2) non-safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain postaccident monitoring equipment (RG 1.97, Category 1 and 2 postaccident monitoring equipment).

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

To demonstrate compliance with 10 CFR 50.49(b)(1), the applicant provided a list of systems and their components required to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs). The systems

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identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of LOCAs or HELBs that have components located in a harsh environment are listed below. This list was reviewed and found acceptable by the staff.

System

(1) reactor coolant system
(2) safety injection system
(3) gaseous nitrogen system
(4) residual heat removal system
(5) chemical and volume control system
(6) main steam system
(7) auxiliary steam system
(8) feedwater and auxiliary feedwater
(9) service water system
(10) reactor plant and process sampling system
(11) postaccident sampling system
(12) emergency diesel generator supporting system
(13) cooling water system
(14) lubrication system
(15) fuel oil supply system
(16) primary plant component cooling water system
(17) boron recovery system
(18) recirculation spray system
(19) quench spray system
(20) fuel pool cooling and purification system
(21) steam generator blowdown system
(22) combustible gas control system
(23) containment isolation components (all applicable fluid systems)
(24) containment vacuum leak monitoring system
(25) control room air conditioning system
(26) service building ventilation system
(27) emergency diesel generator building ventilation system
(28) intake structure ventilation system
(29) safeguards area ventilation system
(30) main steam valve area ventilation system
(31) MCC room ventilation system
(32) cable vault and rod control area ventilation system
(33) auxiliary building and radwaste area ventilation system
(34) supplementary leak collection system
(35) alternate shutdown panel ventilation system
(36) containment ventilation systems
(37) radiation monitoring system
(38) fuel handling system
(39) FW booster pump
(40) electrical systems

To demonstrate compliance with 10 CFR 50.49(b)(2), the applicant stated that there is no non-safety-related electrical equipment whose failure under postulated environmental conditions can prevent the accomplishment of safety functions by safety-related equipment. To determine compliance with 10 CFR 50.49(b)(2), the staff relies on the applicant's compliance with IEEE Standard 384-1974 as modified by RG 1.75 to show electrical and physical separation between safety-related and non-safety-related electrical equipment, and on

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the applicant's response to IE Information Notice 79-22. The staff has reviewed and evaluated the applicant's compliance with RG 1.75 and finds it acceptable. The applicant has also conducted a study in response to the concerns addressed by the staff in IE Information Notice 79-22, "Qualification of Control Systems," dated September 14, 1979. The staff review found the applicant's response to the concerns addressed in IE Information Notice 79-22 acceptable. On this basis, the staff concludes that the applicant's compliance with 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant has identified a number of alternative methods of meeting the intent of RG 1.97. The staff will determine the acceptability of these alternative methods as part of its review for conformance with RG 1.97. This review may impact the environmental qualification program and may result in the addition of equipment to the program.

3.11.3.2 Qualification Methods

(1) Electrical Equipment in a Harsh Environment

Detailed criteria for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in NUREG-0588 are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The staff has reviewed the methods used by the applicant to demonstrate qualification and concluded that they are in compliance with the requirements of NUREG-0588, Category II.

(2) Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Section III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualification:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be used for determining the environmental conditions associated with LOCAs or HELBs, inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the environmental conditions established by the applicant.

(1) Temperature, Pressure, and Humidity Conditions Inside Containment

The applicant provided the LOCA/MSLB profiles used for equipment qualification program submittals. The peak values resulting from these profiles are as follows:

Maximum temperature:	333°F
Maximum pressure:	45.0 psig
Humidity:	100%

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

(2) Temperature, Pressure, and Humidity Conditions Outside Primary Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs outside containment. The criteria used to define the location of the HELBs are described in the FSAR Section 3.6. The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the peak temperatures identified by the applicant are acceptable, with the exception of the issue of superheated steam discussed in Section 3.6.1 of this supplement.

(3) Submergence

The submergence potential has been determined by the applicant to be below 708 feet 1 inch inside the containment and at various elevations in buildings outside the containment building. The applicant has taken appropriate corrective actions to either justify submerged operation, or to relocate or qualify the affected equipment.

(4) Chemical Spray

A chemical spray inside containment may be used to mitigate the effects of an accident. The applicant has appropriately included this parameter in the evaluation of equipment located inside containment.

(5) Aging

The aging program requirements for electrical equipment at Beaver Valley Unit 2 are defined in Category II of NUREG-0588. Category II delineates two aging programs. Valve operators committed to IEEE Std 382-1972 and motors committed to IEEE Std 334-1971 must meet the Category I guidelines in NUREG-0588. This requires that all known degrading influences be considered and included in the aging program. Justification for excluding pre-aging of equipment in type testing must be established on the basis of equipment design and application of state-of-the-art aging techniques. A qualified life is to be established for each equipment item. For other equipment, the qualification program should address aging to the extent that equipment composed in part of materials susceptible to the effects of aging should be identified and a schedule for periodically replacing the equipment or the material should be established.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. The applicant committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American Nuclear Society/American National Standards Institute Standard ANS-3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include: (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate.

The applicant has described a program that incorporates the above guidelines and has stated that the maintenance/surveillance program will be implemented at the time of fuel load.

(6) Radiation (Inside and Outside Containment)

The applicant has provided values for the radiation levels postulated to exist following a LOCA. The application and methodology to determine these values were presented to the applicant in NUREG-0588 and NUREG-0737. The staff review determined that the values to which equipment was qualified enveloped the requirements identified by the applicant.

The maximum value specified by the applicant for use in equipment qualification inside containment, and in areas outside containment is 2×10^8 rads (gamma plus beta). This value is acceptable for use in the qualification of equipment.

3.11.3.4 Outstanding Equipment

For items not having complete qualification documentation, the applicant must provided a commitment for corrective action and a schedule for completion. All items must have full qualification and the applicant must inform the staff that all equipment is qualified before an operating license is granted. By letters

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dated May 18 and 25, 1987, the applicant confirmed that all equipment within the scope of 10 CFR 50.49 is environmentally qualified and that a maintenance/surveillance program has been implemented.

3.11.4 Environmental Qualification Audit

On November 18 through November 20, 1986, the staff, with assistance from EG&G Idaho, Inc., conducted an audit of the applicant's qualification files and equipment installed at the plant. Ten files were audited to determine if the documents in the qualification files supported the qualification status determined by the applicant.

The files selected for audit were:

(1) Barton Pressure Transmitter, File No. 001/ESE-01A
(2) ASCO Solenoid Valve, File No. 001/HE-02/5
(3) Borg Warner Valve Actuator, File No. 2BV-92
(4) RDF Corp. RTD, File No. 001/EST-06
(5) Minco RTD, File No. 001/ESE-42A
(6) Conas Connector, File No. 001/HE-08
(7) Westinghouse Pump Motor, File No. 2BV-24
(8) Limitorque Actuator, File No. 2BV-67
(9) Okonite 600V Power Cable and Splice, File Nos. 2BV-312 and 2BV-312 (931B)
(10) Level Indicator by Fluid Components Inc., File No. 2BV-635

Several deficiencies were noted and discussed with the applicant at the time of the audit and this information was transmitted to the applicant by letter dated March 5, 1987. The applicant proposed acceptable corrective measures in the form of additional information and file revisions to eliminate the deficiencies cited.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location, and installation are consistent with qualification documents. No discrepancies were discovered.

3.11.5 Conclusions

The staff has reviewed the Beaver Valley Unit 2 program for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment. The purpose of the review was to determine the adequacy and scope of the qualification program and to verify that the methods used to demonstrate qualification are in compliance with applicable regulations and standards.

On the basis of the results of its review, the staff concludes that the applicant has demonstrated compliance with the requirements for environmental qualification as outlined in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections III, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria as specified in NUREG-0588. Therefore, confirmatory issue 14 is considered closed.

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Table 3.1 Summary of PVORT audit for Beaver Valley Unit 2

Equipment description	Plant I.D.	Function	Findings (note)	Resolution (note)	Status (note)
Boron recovery system to PRT check valve (Atwood and Morrel 3" check valve)	2RCS-V56 (NSSS)	Valve normally closed. Valve opens to fill PRT. Valve closes for containment isolation.	--	--	Closed
RHR suction from RCS hot-leg isolation valve (Westinghouse 12" gate valve)	2RHS-MOV701B (NSSS)	Valve normally closed. Valve opens to take RHR suction from RCS. Valve acts as an RCS pressure boundary.	--	--	Closed[a]
Low head safety injection injection to RCS hot-leg or cold-leg isolation valve (Westinghouse 10" gate valve)	2SIS-MOV864A (NSSS)	Valve normally closed. Valve opens for RCS hot-leg recirculation.	--	--	Closed
Low head safety injection pump (Gould 3000 gpm pump)	2SIS-P21B (NSSS)	Pump normally shut down. Pump starts for low-pressure coolant injection.	--	--	Closed
Emergency boration isolation valve (Velan 2" globe valve)	2CHS-MOV350 (NSSS)	Valve normally closed. Valve opens for emergency boration backup to normal boration path.	--	--	Closed

Table 3.1 (Continued)

Equipment description	Plant I.D.	Function	Findings (note)	Resolution (note)	Status (note)
Boron recovery system to PRT isolation valve (Westinghouse 3" diaphragm)	2RCS-AOV519 (NSSS)	Valve normally closed. Valve opens for spray inside of PRT and closes for containment isolation.	--	--	Closed[b]
Nitrogen supply to safety injection tank 21A isolation valve (Target Rock 1" gate valve)	2GNS-SOV853A (NSSS)	Valve normally closed. Valve opens to pressurize injection tank. Valve closes for nitrogen isolation.	--	--	Closed[b]
Residual heat removal pump (Ingersoll Rand 4000 gpm pump)	2RHR-P21A (NSSS)	Pump normally in standby. Pump started for residual heat removal.	--	--	Closed[b]
Steam generator blowdown isolation valve (Masoneilan 3" globe valve)	2BDG-AOV100B1 (BOP)	Valve normally open to allow steam generator blowdown. Valve closes to isolate blowdown.	Note[h]	Note[d]	Closed
Component cooling water pump P21C discharge check valve (TRW 20" check valve)	2CCP-V6 (BOP)	Valve opens to allow pump flow or closes to isolate an idle pump.	--	--	Closed

Table 3.1 (Continued)

Equipment description	Plant I.D.	Function	Findings (note)	Resolution (note)	Status (note)
Standby service water system supply valve (Henry Pratt 30" butterfly valve)	2SWE-MOV116B (BOP)	Valve normally closed as a division valve between Trains A and B. Valve opens on a standby pump run signal.	--	--	Closed
Fuel pool cooling pump (Gould 750 gpm pump)	2FNC-P21A (BOP)	Pump operates to remove heat buildup in the spent fuel pool.	Note[c]	Note[d]	Closed
Service water pump (Byron Jackson 15,000 gpm pump)	2SWS-P21B	Two pumps out of three normally operating to remove auxiliary system heat loads. One pump out of three required for safe shutdown.	--	--	Closed
Containment instrument air isolation valve (Xomox 3" plug valve)	2IHC-MOV130 (BOP)	Valve normally open. Valve closes on containment isolation signal.	--	--	Closed
Main steam isolation valve (Crosby 32" ball valve)	2MSS-HYV101A (BOP)	Valve normally open. Valve closes to isolate main steam line.	Note[f]	Note[d]	Open[e]

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Table 3.1 (Continued)

Equipment description	Plant I.D.	Function	Findings (note)	Resolution (note)	Status (note)
Hydrogen combiner inlet isolation valve (Target Rock 2" globe valve)	2HCS-SOV114A (BOP)	Valve normally closed. Valve opens to provide flow from containment vacuum pumps.	--	--	Closed[b]
Cooling water to primary component cooling heat exchanger isolation valve (Henry Pratt 30" butterfly valve)	2SWS-MOV106B	Valve normally open. Valve closes to isolate service water from Train B.	--	--	Closed[b]
Auxiliary feedwater pump (Terry Turbine 750 gpm pump)	2FWE-P22	Pump normally in standby. Pump starts to provide water to steam generators.	Note[i]	Note[d]	Closed[b]
All pumps and valves important to safety	--	Operates as required during the life of plant under normal and accident conditions.	Note[g], [j], k, l, m, n, o, p,	Note[d]	Closed

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a. This component is an RCS boundary isolation valve; however, leak rate testing is not being performed. This item is considered to be closed pending acceptance of the Technical Specifications and its testing requirements.

b. This item was visually inspected for completeness of installation. Qualification documentation was not reviewed except on a limited basis.

Table 3.1 (Continued)

c. (SPECIFIC ISSUE) During qualification documentation review, it was found that the pump and motor installation did not meet the design flow or maximum vibration requirements. The applicant was aware of the deficiencies. In the letter dated April 16, 1987, the applicant verified that the pump develops the flow rate and total head required to support the safety system analyses. The motor support stand has been stiffened to satisfy the vibrating criteria. This issue is closed.

d. At the conclusion of the site audit, the staff summarized the open issues. The applicant was informed of the appropriate actions necessary to resolve the specific and generic issues before fuel load.

e. Qualification status will be "closed" upon resolution of specific and generic issues.

f. (SPECIFIC ISSUE) This component was partially qualified, however, when testing was being performed, a design flaw was identified. The flaw resulted in failure of the actuator. At the time of the site audit, the applicant had not determined a repair. The applicant shall (1) determine a suitable modification and repair, (2) make the necessary repairs, (3) perform testing to ensure modifications are adequate, and (4) ensure that the component is qualified. These requirements shall be confirmed before fuel load. In the letter dated May 15, 1987, the applicant stated it has replaced the three Crosby valves with Atwood-Morrill valves. This is acceptable pending confirmation of qualification.

g. (GENERIC ISSUE) The potential for flow-disrupting conditions that could affect check valve operability has not been assessed. The applicant has committed to participate in the INPO check valve workshop and to verify design against INPO identified criteria. In the April 16, 1987 letter, the applicant committed to incorporate any requirements resulting from INPO SOER 86-3. This issue is closed.

h. (SPECIFIC ISSUE) The review of the structural integrity analysis revealed that justification was not provided for omitting consideration of direct seismic vertical loads, torsional moments and measured amplification factors. The applicant shall provide justification for not including (1) the effects and (2) the amplification factors. In the letter dated October 27, 1986 the applicant determined that the effects of the vertical seismic load and amplification are insignificant. This issue is closed.

i. (SPECIFIC ISSUE) The frequency for turbine disassembly differs from the vendor's recommendations. The applicant shall provide assurance that the turbine vendor's recommendations for maintenance including disassembly are invoked by the Beaver Valley Unit 2 maintenance program. In the letter dated October 27, 1986 the applicant agreed to follow the vendor's maintenance program. This issue is closed.

Table 3.1 (Continued)

j. (GENERIC ISSUE) At the conclusion of the PVORT audit, it was apparent that a complete list of active pumps and valves had not been provided in the FSAR. At the site audit, the applicant committed to confirm that all active NSSS and BOP pumps and valves are correctly identified in the FSAR. The April 16, 1987 letter indicated that the information has been included in Amendment 16 (January 1987). This issue is closed.

k. (GENERIC ISSUE) Some preservice tests required to be completed before fuel load have not yet been performed. At the site audit, the applicant committed to confirm that all appropriate preservice tests have been completed before fuel load. This issue is closed.

l. (GENERIC ISSUE) Some pumps and valves important to safety have not been completely qualified and installed. At the site audit, the applicant committed to confirm that all pumps and valves important to safety are completely qualified and installed before fuel load. Also, the applicant shall confirm that the original loads used in tests and analyses to qualify pumps and valves important to safety are not exceeded by any new loads (i.e., design load reconciliation). The response dated April 16, 1987 stated that all pumps and valves except the MSIVs are qualified and installed. In addition, the design load reconciliation task has been completed. This issue is closed.

m. (GENERIC ISSUE) Similarity statements were not provided in all cases where similarity qualification was utilized. The similarity statement should include a discussion about the difference between qualification and installed conditions. The applicant shall evaluate its document files to ensure all similarity concerns have been addressed. The response dated April 16, 1987 described the basis for qualification by similarity. This issue is closed.

n. (GENERIC ISSUE) Document retrieval was inconsistent. The applicant shall evaluate its document control system to (1) determine its effectiveness, (2) reduce the potential for human error, and (3) ensure that all personnel who use the document retrieval system are adequately trained. As indicated in the April 16, 1987 letter, the applicant has evaluated and revised the document retrieval system. This issue is closed.

o. (GENERIC ISSUE) Inconsistencies were identified in nonconformance and disposition (N&D) tag controls. The applicant shall (1) provide evidence that the inconsistencies have been completed and accepted and (2) confirm that N&D and rejection tags for all safety-related pumps and valves have been satisfactorily resolved before fuel load. In the April 16, 1987 letter, the applicant described various programs that are used to track the status and completion of all work items. This issue is closed.

Table 3.1 (Continued)

p. (GENERIC ISSUE) The FSAR figures do not identify check valves by an identification label. The applicant shall confirm, before fuel load, that all check valves are correctly identified in the FSAR figures. The April 16, 1987 letter described the traceability from the FSAR figures to the plant design drawings. This issue is closed.

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.3 Fuel Coolability Evaluation

In the SER, the staff stated that the structural analysis of the reactor internals under loss-of-coolant accident (LOCA) was performed using Multiflex 3.0 instead of the previously approved Multiflex 1.0. Accordingly, the staff concluded that the issue of combined seismic and LOCA loads was a confirmatory issue pending completion of the Multiflex 3.0 review.

In the analysis performed using Multiflex 3.0, the structural response of the reactor internals was determined for breaks in the hot leg, cold leg, crossover leg, and in the large reactor coolant loop (RCL) branch lines. Since these LOCA analysis were performed, leak-before-break analyses of the RCL and large branch lines have been submitted, reviewed, and approved by the staff. These analyses have demonstrated that the dynamic effects of postulated pipe breaks in the RCL, 14-inch pressurizer surge line, 12-inch accumulator injection lines, 10- and 12-inch residual heat removal lines, 6-inch safety injection lines, and the 8-inch RCL bypass lines need not be included in the design basis. The only remaining LOCA loads in the design basis for dynamic effects on the reactor internals are those from postulated pipe breaks in 4-inch-and-under RCL branch lines.

The staff believes that the design-basis LOCA loading on the reactor internals is considerably smaller than that originally evaluated by Multiflex 3.0. Likewise, it is the staff's judgment that the design-basis LOCA loading is considerably less than that evaluated by Multiflex 1.0 for other 3-loop Westinghouse plants with reactor internals design similar to that of Beaver Valley Unit 2. Accordingly, there is reasonable assurance that the design of the Beaver Valley Unit 2 reactor internals is acceptable for the combination of seismic and LOCA loading and that a review of Multiflex 3.0 is no longer required for the issuance of the Beaver Valley Unit 2 operating license.

The applicant is preparing a more detailed basis to support the above evaluation and has committed to provide this information to the NRC. The staff's future evaluation of this information will be tracked by licensing action TAC 62904; meanwhile, confirmatory issue 21 is considered closed on the basis of the above discussion.

4.3 Nuclear Design

4.3.2 Fuel System Design

4.3.2.1 Power Distribution

The SER indicated that a ±5% ΔI band width would be incorporated in the Beaver Valley Unit 2 Technical Specifications. The SER also indicated that

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the Technical Specifications would incorporate an axial power distribution monitoring system (APDMS).

The staff now concurs with issuance of the Beaver Valley Unit 2 Technical Specifications with no APDMS specification, the axial flux difference (AFD) of ±7% in Technical Specification 3.2.1, an F_Q of 2.32 in Technical Specification 3.2.1, and an $F_{\Delta H}^N$ multiplier of 0.3 in Technical Specification 3.2.3. The staff's concurrence is based on the following:

(1) A telephone conversation on May 22, 1987 between the applicant, Westinghouse, and the staff, during which it was indicated to the staff that (a) safety analyses have been performed and will be documented shortly with all the above parameters as stated and (b) the results are within regulatory limits

(2) The consideration that: (a) the APDMS is not used during low-power operation; (b) the AFD specification does not apply if power does not exceed 50% power; (c) the F_Q specification allows the limit to double in value at 50% of rated power (and staff experience indicates that a value of nearly 4 is not likely to be attainable); and (d) the $F_{\Delta H}^N$ multiplier has been found acceptable over the full-power operating range for other similar plants.

The staff will provide a final evaluation of these items when documentation is received and before the full-power license is issued.

4.4 Thermal-Hydraulic Design

4.4.4 Loose Parts Monitoring System

In the SER, the staff stated that the applicant should include in the Technical Specifications (TS) a section on the loose parts monitoring system (LPMS) addressing operability and surveillance requirements similar to such a specification in the Westinghouse Standard Technical Specifications. The proposed specification would be in compliance with the guidelines of Regulatory Guide 1.133.

During the preparation of the TS, the applicant requested that the Beaver Valley Unit 2 TS not include a requirement for the LPMS in accordance with the letter dated September 18, 1984 from G. Knighton of NRC to J. Carey of Duquesne Light Company. The letter stated that the TS for a second unit should be virtually identical to those of the previously licensed unit, and that the only changes are those which involve actual design differences or new requirements. Since the Beaver Valley Unit 1 TS do not include a requirement for LPMS, the staff approved removing the LPMS specification from Beaver Valley Unit 2. The applicant should update the FSAR to reflect the removal of the LPMS technical specification.

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4.4.7 Inadequate Core Cooling Instrumentation (ICCI)

In SSER 2 the staff concluded that the design of the Beaver Valley Unit 2 ICCI is in conformance with the guidelines of NUREG-0737 and is acceptable. The applicant, however, has been requested to submit a letter report to inform the staff upon completion of installation.

By letter dated May 12, 1987, the applicant stated that the ICCI was completed by field change notices 10607 and 10616. This is responsive to the staff's concern. Confirmatory issue 50 is considered closed.

5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

5.2.4.3 Evaluation of Compliance With 10 CFR 50.55a(g)

By letter dated April 1, 1987, the applicant committed to submit the Inservice Inspection (ISI) Program by June 1, 1988. As stated in SSER 1, the staff still plans to complete review of the program before the unit commences the first refueling outage. The review will be tracked by licensing action TAC 62873; no other prelicensing action will be taken by the staff and open issue 4(b) is considered closed.

This following section and Appendix R were prepared with the technical assistance of U.S. Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory (INEL).

This evaluation supplements conclusions in this section of the SER which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The SER reported that the staff considered the review of the preservice inspection (PSI) program for the reactor coolant pressure boundary to be an open issue subject to the applicant

(1) docketing a complete and acceptable Preservice Inspection Program Plan

(2) addressing the effectiveness of the ASME Code-required ultrasonic examination of the cast stainless steel weldments in the primary reactor coolant system piping and fittings

(3) submitting all relief requests with a supporting technical justification

Since the SER was issued, the staff has completed its review of the following information:

(1) the FSAR through Amendment 13 issued January 31, 1987

(2) a December 26, 1985 submittal from the applicant containing the "Beaver Valley Power Station Unit No. 2 Preservice Inspection Program," and enclosures addressing staff concerns with regards to the applicant's position on weld overlay and the ultrasonic examination of the cast stainless steel weldments in the primary reactor coolant system

(3) NRC Region I Inspection Report No. 50-412/86-05 (submittal dated April 2, 1986) with regard to NRC inspectors observing ultrasonic examinations in progress on three cast stainless steel weldments in the primary reactor coolant system

(4) a May 13, 1986 letter from the applicant containing information relative to the PSI examination of component supports and the augmented examination of 2-inch-and-smaller welds in the break exclusion zone (BEZ)

(5) a January 13, 1987 letter from the applicant withdrawing Relief Request No. 1 with regard to the volumetric examination of the reactor pressure vessel nozzle inside radius sections

(6) a January 23, 1987 letter from the applicant discussing an Enhanced Component Support Program with regard to multiple stream selection of component supports during PSI

(7) a January 30, 1987 letter from the applicant which identified the PSI Program criteria and methodology for visual examination (VT-3) of component supports which were selected for examination where a portion of the support is covered/buried with insulation

(8) a March 12, 1987 letter from the applicant containing a relief request with regard to the preservice examination of piping welds that are inaccessible and, therefore, could not be completed in accordance with ASME Code Section XI

(9) an April 6, 1987 letter from the applicant containing relief requests with regard to specific examinations that could not be completed in accordance with ASME Code Section XI on Class 1 and Class 2 pressure vessels

On the basis of the construction permit issuance date of May 3, 1974, 10 CFR 50.55a(g)(2) requires that components (including supports) that are classified as ASME Code Class 1 and 2 must meet the preservice examination requirements in the editions and addenda of Section XI of the ASME Code in effect 6 months before the date of issuance of the construction permit. The components (including supports) may meet requirements in subsequent editions and addenda of the Code that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. In order to comply with more recent Code editions and addenda, the applicant has elected to incorporate ASME Code Section XI 1980 Edition, Winter 1980 Addenda and the 1974 Edition, Summer 1975 Addenda requirements as referenced in 10 CFR 50.55a(b) and include additional welds for examination based on the 1983 Edition, Winter 1983 Addenda of the Code for compatibility with anticipated inservice inspection (ISI) requirements.

In the December 26, 1985 submittal, the applicant discussed the ultrasonic technique for examination of austenitic piping welds with OD weld-deposited clad overlay. This technique was developed for examinating piping welds with corrosion-resistant cladding at the Electric Power Research Institute Nondestructive Examination Center by NES for the Perry Nuclear Power Plant. The technique employs dual-element 45-degree refracted longitudinal search units, 3/4 inch x 3/4 inch or 1 inch x 1 inch in size. This technique was demonstrated and found acceptable at Beaver Valley Power Station Unit 2 using overlay mockups with simulated cracks representing as-built piping welds. The butt weld in one of the mockups proved to be acoustically the worst case for detecting a simulated crack through the weld, since it could not be detected using conventional shearwave techniques. The applicant reported that the ultrasonic examiner training,

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and conversion factors to be applied to the in-plant PSI examinations, were established using these mockups.

The December 26, 1985 submittal also addressed the effectiveness of the Code-required ultrasonic examination of the cast stainless steel weldments in the primary reactor coolant system piping and fittings. The applicant reported that the examination technique used is the same as was successfully demonstrated at NRC Region 2 for use on Shearon Harris Nuclear Power Plant main coolant loop piping CF8M fittings and elbows. This qualification was performed on a centrifugally cast stainless steel-to-statically cast stainless steel (CCSS/SCSS) welded mockup owned by Region 2. The results of this demonstration are given in NRC Report No. 50-400/84-40. The region reported that this technique was successful in detecting the I.D. reflectors, including cracks, and that the test specimens represented examination conditions much worse than those expected to be experienced during the examination of the reactor coolant loop piping at Shearon Harris.

During the week of February 24-28, 1986, NRC Region I inspectors observed ultrasonic examinations in progress on portions of three cast stainless steel welds in the reactor coolant system at Beaver Valley Unit 2. It was reported (NRC Report No. 50-412/86-05) that the examinations were being performed using the refracted longitudinal angle-beam focused transducers and that the ultrasonic equipment was calibrated using the appropriate calibration standard. The scanning sensitivity was 10 dB greater than the reference level, and indications were being recorded at the reference level. The inspectors also reported that the examinations were performed by qualified technicians in accordance with approved procedures.

On this basis, the staff considers the issue of the preservice ultrasonic examination of welds in the primary coolant system at Beaver Valley Power Station, Unit 2 to be resolved.

The May 13, 1986 submittal contained clarifications with regard to the preservice examinations of component supports. During discussions with the staff, it was agreed that for the application of IWF-2200(b), which requires that "All examinations shall be performed following the initiation of hot functional tests," only systems with an operating temperature greater than 200°F would require examination following the initiation of hot functional tests.

In the May 13, 1986 submittal, and also in the January 23, 1987 submittal, the applicant confirmed that the selection of component supports for PSI utilizing IWF-2510(a) and (b) will meet the intent of providing an examination baseline for ISI. The applicant indicated that, in addition to utilizing multiple stream and multiple component criteria for establishment of "all in one train" of component supports, all Class 1 component (piping) supports applicable to Class 1 integral piping attachments, which were selected from any of the multiple trains, would also be included in the examination requirements.

The January 30, 1987 submittal described the PSI Program criteria and methodology for visual examination (VT-3) of component supports which were selected for examination where a portion of the support (within the IWF examination boundary) is covered/buried with insulation. The applicant stated that the insulation will not be removed during PSI examination, based on ASME Code Section XI,

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IWF-1300(e), which states in part, "Where the mechanical connection of a nonintegral support is buried within the component insulation, the support boundary may extend from the surface of the component insulation provided the support either carries the weight of the component or serves as a structural restraint in compression." An alternative to the Code is being utilized to include those supports not otherwise covered by this exemption. The applicant has stated that the insulation shall be removed and visual examination (VT-3) shall be performed for the balance of the component support to the IWF boundary within the insulated area for the following exceptions:

(1) when relevant indications are observed, which have been evaluated as unacceptable for continued service and which are observed adjacent to the portion covered/buried by insulation

(2) when bulges or insulation distortions are observed in the area contiguous to the component support

These exceptions shall apply when any component support has relevant indications, regardless of the exclusion by IWF-1300(e). The acceptance criteria for component supports selected for examination will be in compliance with ASME Code Section XI, 1980 Edition, Winter 1981 Addenda, IWF-3410.

Requests for relief, from the ASME Code Section XI requirements which the applicant has determined to be impractical for systems and components within the reactor coolant pressure boundary, were received in submittals dated March 12 and April 6, 1987. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and concluded that in all cases, except the request for relief from the preservice volumetric examination of the steam generator nozzle inside radius sections (for details see Section III.E in Appendix R to this report), the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

Considering its review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that, with the exception of the relief request for the preservice volumetric examination of the steam generator nozzle inside radius sections as identified above, the preservice inspection program for the reactor coolant pressure boundary at Beaver Valley Power Station, Unit 2 is acceptable and in compliance with 10 CFR 50.55a(g)(2). The detailed evaluation supporting this conclusion is provided in Appendix R to this report. The evaluation contained in this section, Section 6.6.3, and Appendix R closes open issue 4(a).

5.3 Reactor Vessel

5.3.4 Pressurized Thermal Shock (PTS)

10 CFR 50.61 "Fracture toughness requirements for protection against pressurized thermal shock events," requires that the applicant submit projected values of RT_{PTS} (at the inner vessel surface) of reactor vessel beltline materials by

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giving values from the time of submittal to the expiration date of the operating license. The assessment must specify the bases for the projection, including the assumptions regarding core loading patterns. This assessment must be updated whenever changes in core loadings, surveillance measurements, or other information indicate a significant change in projected values.

Staff review of the Beaver Valley Unit 2 FSAR indicates that the pressure vessel materials have low copper and nickel content. This, combined with the fact that Beaver Valley Unit 2 will have low-leakage loading patterns, suggests that the Unit 2 reactor pressure vessel can easily meet the requirements of 10 CFR 50.61 for the initial operating period. Staff review and approval of the applicant's submittal is not a requirement for plant licensing. Upon receipt of the applicant's submittal, the staff will issue a safety evaluation report, which is not associated with the SER or its supplements. The review of the applicant's submittal will be tracked by licensing action TAC 64793.

5.4 Component and Subsystem Design

5.4.7 Residual Heat Removal System

In Supplement No. 1 to the SER, the staff stated that the natural circulation test requirements of Branch Technical Position (BTP) BTP RSB 5-1 remain unresolved (confirmatory issue 22). The only natural circulation tests performed at a Westinghouse plant to date that meet the requirements of BTP RSB 5-1 are the Diablo Canyon tests. However, Diablo Canyon is a four-loop plant and there may be other significant differences between the two plants, such as upper vessel head temperatures. In view of this, the applicant can demonstrate that the Diablo Canyon test is applicable to Beaver Valley Unit 2 with a demonstration of thermal and hydraulic similarities in the core, upper vessel head, and loops. As an alternative, the applicant can perform a natural circulation and boron mixing test from high power to cold shutdown at Beaver Valley Unit 2. This issue must be satisfactorily resolved before startup following the first refueling outage. By letter dated May 11, 1987, the applicant provided Westinghouse report WCAP-11461, "Beaver Valley Unit 2 Natural Circulation Boron Mixing Evaluation Program Report." The report demonstrates the applicability of the Diablo Canyon boron mixing results to Beaver Valley Unit 2.

The staff has determined that there is reasonable assurance that the plant can operate for one cycle until this issue is resolved since (1) natural circulation has been demonstrated on other Westinghouse plants, (2) operator training will be provided on a simulator which adequately represents Unit 2 performance with regarding to natural circulation, (3) systems required for natural circulation cooldown (e.g., auxiliary feedwater and residual heat removal system) are safety grade, and (4) there is an ample auxiliary feedwater supply from seismic Category I sources.

On the basis of the applicant's submittal, the staff determined that there is no need to impose a license condition on the issue of the natural circulation test in the operating license of Beaver Valley Unit 2. Completion of review is not needed before issuance of the operating license. Confirmatory issue 22 is considered closed. This issue will be tracked to its completion by licensing action TAC 62905.

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6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.1 Containment Structure

In the SER, the staff stated that

> The applicant also performed a sensitivity study and found that the initial conditions that result in the maximum depressurization time are initial containment pressure of 9.85 psia, initial containment temperature of 85°F, initial containment dewpoint of 85°F, service water temperature of 86°F, and RWST temperature of 50°F. These are the limiting values that will be allowed by the Technical Specifications.

The staff does not intend to impose a limiting value on containment atmospheric humidity, nor does the staff intend to require by Technical Specifications that humidity be monitored. Since the maximum depressurization time after a loss-of-coolant accident (post-LOCA) would be attained from the above initial conditions, among them 100% relative humidity (i.e., 85°F dewpoint and temperature), any relative humidity less than 100% would not result in the maximum calculated post-LOCA depressurization time. It would not make sense to impose a limiting value of 100% for relative humidity; the staff will, however, impose limits on containment pressure and temperature. This clarifies the subject statement.

6.2.1.3 Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents

The SER indicated that the model used for calculating the LOCA blowdown transient was described in Westinghouse letter NS-TMA-2075, dated April 25, 1979. By letter dated October 4, 1984, Westinghouse submitted this model in Topical Report WCAP-10325, "Westinghouse LOCA Mass and Energy Release Model for Containment Design--March 1979 Version." This report was reviewed and found acceptable by the staff as indicated in the safety evaluation transmitted to Westinghouse, by letter dated February 17, 1987. On this basis, confirmatory issue 24 is considered resolved.

6.2.2 Containment Heat Removal Systems

By letter dated April 13, 1987, the applicant responded to a staff concern identified as confirmatory issue 25 in the SER. This confirmatory issue asked the applicant to justify the 50% sump blockage assumption used in assessing the design and performance of the containment sump. The 50% sump blockage assumption is recommended by RG 1.82, Revision 0 under the condition that the flow velocity at the inner screen of the sump is less than 0.2 ft/sec. The Beaver Valley Unit 2 sump design does not satisfy this condition; therefore, additional justification from the applicant to apply the 50% sump blockage assumption was needed.

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In the letter of April 13, 1987, the applicant postulated the worst break at the steam generator hot leg nozzle in steam generator cubicle "C". Reflective metallic insulation is used to cover the primary jet target area and thus it will become the debris of concern for sump blockage. Since the structural features and various gratings between the target area and the containment floor can collect large pieces of insulation debris, the debris that most likely can reach the containment floor will be small pieces that can fit through the gratings. The debris that does reach the containment floor will generally be deposited in an area approximately 36 feet from the containment sump screens. With two trains of recirculation flow in operation, the applicant calculated that the maximum flow velocity in the area where debris will be deposited, is 0.26 ft/sec.

The staff has reviewed the applicant's analysis and finds that, with the exception of the thin (0.0025 inch) inner foil, the flow velocity of 0.26 ft/sec is insufficient to transport the reflected metallic insulation in any other debris form. As indicated in Table 3.7 of NUREG-0897, Rev. 1, "Containment Emergency Sump Performance," the inner foil in the form of either a large single sheet or cut-up single sheets can be transported at the flow velocity greater than 0.25 ft/sec. However, the test results, shown in Appendix E of NUREG-0897, Rev. 1, indicate that jet forces resulting from a pipe rupture would tear the reflected metallic insulation apart into many irregularly shaped small pieces instead of into large pieces of sheet metal. Considering these test results as well as the Beaver Valley Unit 2 plant-specific structural features (e.g., gratings) between the jet target area and the containment floor, the staff concludes that having a large single sheet of inner foil reach the sump screens is very unlikely.

In addition, the test results in NUREG/CR-3616, "Transport and Screen Blockage Characteristics of Reflected Metallic Insulation Materials," indicate that the small pieces of inner foil need larger velocities to be transported. Further, their movement will be in a sliding rather than a folding and tumbling mode. Thus, the small pieces sliding along the bottom of the sump can be partially caught under the screen but will not flip up against the screen and block it. On this basis, the staff concludes that the 50% blockage assumption is acceptable for the Beaver Valley Unit 2 containment sump design.

On the basis of the above evaluation, confirmatory issue 25 is considered closed.

6.2.5 Combustible Gas Control in Containment

In the SER, the staff indicated that one hydrogen recombiner is permanently installed in the safeguard area; the other recombiner would be transferred from Beaver Valley Unit 1 and installed in the safeguard area following the onset of an accident. Since issuance of the SER, the applicant has acquired additional recombiners; now two recombiners are located in the Beaver Valley Unit 2 safeguard area. This provides the same degree of safety performance without having to rely on transferring a recombiner.

6.2.6 Containment Leakage Testing Program

By letter dated March 6, 1987, the applicant requested an exemption from certain requirements of Appendix J to 10 CFR 50. Paragraph III.D.2(b)(ii) of Appendix J

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states: "Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than P_a."

Whenever the plant is in cold shutdown (mode 5) or refueling (mode 6), containment integrity is not required. However, if an air lock is opened during modes 5 and 6, Paragraph III.D.2(b)(ii) of Appendix J requires that an overall air lock leakage test at not less than P_a be conducted before plant heatup and startup (i.e., entering mode 4). The existing air lock doors are so designed that a full-pressure (i.e., P_a (44.7 psig)) test of an entire air lock can only be performed after strong backs (structural bracing) have been installed on the inner door. Strong backs are needed because the pressure exerted on the inner door during the test is in a direction opposite to that of the accident pressure direction. Installing strong backs, performing the test, and removing the strong backs requires several hours, during which access through the air lock is prohibited.

When no maintenance has been performed on the air lock that could affect its sealing capability, and the air lock doors have been closed in accordance with the applicant's procedure, and the periodic 6-month test at P_a required by Paragraph III.D.2(b)(i) of Appendix J has been performed on schedule, there is no reason to expect the air lock to leak excessively just because it has been opened in a shutdown or refueling mode. Performing the door seal leak test of Paragraph III.D.2.(b)(iii) of Appendix J is sufficient, in this case, to demonstrate the continuing integrity of the air lock.

Accordingly, the staff concludes that the applicant's proposed approach of substituting the seal leakage test of Paragraph III.D.2(b)(iii) for the full-pressure test of Paragraph III.D.2(b)(ii) of Appendix J is acceptable when no maintenance that could affect sealing capability has been performed on an air lock. Whenever maintenance that could affect sealing capability has been performed on an air lock, the requirements of Paragraph III.D.2(b)(ii) of Appendix J must still be met by the applicant.

The staff has identified the special circumstances for granting this exemption pursuant to 10 CFR 50.12. The purpose of Appendix J to 10 CFR 50 is to ensure that the containment's leaktight integrity can be verified periodically throughout service lifetime so as to maintain containment leakage within the limits specified in the facility Technical Specifications. The proposed alternative test method is sufficient to achieve this underlying purpose because it provides adequate assurance of continued leaktight integrity of the air lock. In addition, at the time this section of Appendix J was revised in 1980, the staff did not contemplate the undue hardship and cost that would result from the requirement to perform a time-consuming, full-pressure test before starting up from even the shortest cold shutdown during which the air lock had been used for entry into the containment. For this reason, the staff has already granted this same exemption to many plants, including Beaver Valley Unit 1. The staff intends to revise Appendix J so that granting similar exemptions will no longer be necessary. Applying the regulation would not serve the underlying purpose of the rule and would result in undue hardship or other costs (10 CFR 50.12(a)(2)(ii) and (iii)) because the applicant has proposed an acceptable alternative test method that accomplishes the intent of the regulation.

In addition, personnel would be exposed to radiation unnecessarily while an overall air lock leakage test was performed at full pressure.

Therefore, a partial exemption from this requirement (10 CFR 50, Appendix J, Paragraph III.D.2(b)(ii)) is justified and acceptable, and the applicant's proposal to adopt Surveillance Requirement 4.6.1.3 of Revision 4 of NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," is also acceptable (NUREG-0452, Rev. 4, was written to accommodate this type of exemption). The requested exemption will be included as part of the operating license.

6.4 Control Room Habitability Systems

In the SER, the control room habitability systems were evaluated and found to keep doses below the General Design Criterion (GDC) 19 standards for a broad spectrum of accidents. However, in FSAR Amendment 13, the applicant submitted additional information indicating that the design-basis accident posing the greatest challenge to the control room habitability systems is the failure of a small line carrying primary coolant outside containment as described in Standard Review Plan (SRP) Section 15.6.2 (NUREG-0800).

The small-break accident is controlling largely because the habitability systems are designed primarily to cope with a large loss-of-coolant accident (LOCA) inside containment. That is, a large LOCA would cause isolation of the control room; pressure would be maintained by bottled gas. The control room would remain isolated for 1 hour and, at that time, leakage from containment would stop because containment pressure again would become less than atmospheric pressure. Thus, the principal source of activity in the control room from a large LOCA is via emergency core cooling system (ECCS) pump leakage. ECCS pump leakage is kept small (0.0094 gpm) and the associated gases are released through high efficiency particulate air (HEPA) filters and charcoal adsorbers. The small break outside containment does not isolate the control room until the radiation level in the control room is raised to above the setpoint and the gases are unfiltered.

The staff performed an independent calculation of the doses in the control room from a small break in accordance with SRP Sections 15.6.6 and 6.4. These doses were found to be below the criteria of GDC 19. Therefore, the control room habitability systems are acceptable.

6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of U.S. Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory (INEL).

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g)

This evaluation supplements conclusions in this section of the SER which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The SER reported that the staff considered the review of the preservice inspection (PSI) program for the Class 2 and Class 3 components to be an open issue subject to the applicant

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(1) docketing a complete and acceptable Preservice Inspection (PSI) Program Plan

(2) providing supporting information with regard to the method that was used to determine that the ASME Code-required volumetric (ultrasonic) examination of the head and shell welds on the reactor coolant filter and seal water heat exchangers is not feasible because of material thickness

(3) submitting all relief requests with a supporting technical justification

Since the SER was issued, the staff has completed its review of the following information:

(1) the FSAR through Amendment 13 issued January 31, 1987

(2) a December 26, 1985 submittal from the applicant containing the "Beaver Valley Power Station Unit No. 2 Preservice Inspection Program," including an enclosure addressing staff concerns with regard to the Class 2 piping weld examinations

(3) a May 13, 1986 letter from the applicant containing information relative to the PSI examination of component supports and the augmented examination of 2-inch-and-smaller welds in the break exclusion zone (BEZ)

(4) a January 23, 1987 letter from the applicant discussing an Enhanced Component Support Program with regard to multiple stream selection of component supports during PSI

(5) a January 30, 1987 letter from the applicant which identified the PSI Program criteria and methodology for visual examination (VT-3) of component supports which were selected for examination where a portion of the support is covered/buried with insulation

(6) a March 12, 1987 letter from the applicant containing a relief request with regard to the preservice examination of piping welds that are inaccessible and, therefore, could not be completed in accordance with ASME Code Section XI

(7) an April 6, 1987 letter from the applicant containing relief requests with regard to specific examinations that could not be completed in accordance with ASME Code Section XI on Class 1 and Class 2 pressure vessels

(8) an April 13, 1987 letter from the applicant discussing the use of fabrication visual examination results on Class 3 support integrally welded attachments to satisfy the ASME Code Section XI preservice examination requirements for the same.

On the basis of the construction permit issuance date of May 3, 1974, 10 CFR 50.55a(g)(2) requires that components (including supports) that are classified as ASME Code Class 1 and 2 must meet the preservice examination requirements in the editions and addenda of Section XI of the ASME Code in effect 6 months before the date the construction permit was issued. The components (including supports) may meet requirements in subsequent editions and addenda

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of the Code that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. In order to comply with more recent Code editions and addenda of the Code, the applicant has elected to incorporate ASME Code Section XI 1980 Edition, Winter 1980 Addenda and the 1974 Edition, Summer 1975 Addenda requirements as referenced in 10 CFR 50.55a(b) and include additional welds for examination based on the 1983 Edition, Winter 1983 Addenda of the Code for compatibility with anticipated ISI requirements. A 10% sample criteria for Class 2 stainless steel systems is utilized in lieu of the 7.5% sample criteria defined in the 1980 Edition, Winter 1983 Addenda.

The May 13, 1986 submittal contained clarifications with regard to the preservice examinations of component supports. During discussions with the staff, it was agreed that for the application of IWF-2200(b), which requires that "All examinations shall be performed following the initiation of hot functional tests," only systems with an operating temperature greater than 200°F would require examination following the initiation of hot functional tests. In this submittal, and also in the January 23, 1987 submittal, the applicant confirmed that the selection of component supports for PSI utilizing IWF-2510(a) and (b) will meet the intent of providing an examination baseline for ISI.

The January 30, 1987 submittal described the PSI Program criteria and methodology for visual examination (VT-3) of component supports which were selected for examination where a portion of the support (within the IWF examination boundary) is covered/buried with insulation. The applicant stated that the insulation will not be removed during PSI examination, based on ASME Code Section XI, IWF-1300(e), which states in part, "Where the mechanical connection of a nonintegral support is buried within the component insulation, the support boundary may extend from the surface of the component insulation provided the support either carries the weight of the component or serves as a structural restraint in compression." An alternative to the Code is being utilized to include those supports not otherwise covered by this exemption. The applicant has stated that the insulation shall be removed in that area and visual examination (VT-3) shall be performed for the balance of the component support to the IWF boundary within the insulated area for the following exceptions:

(1) when relevant indications are observed, which have been evaluated as unacceptable for continued service and which are observed adjacent to the portion covered/buried by insulation

(2) When bulges or insulation distortions are observed in the area contiguous to the component support

These exceptions shall apply when any component support has relevant indications, regardless of the exclusion by IWF-1300(e). The acceptance criteria for component supports selected for examination will be in compliance with ASME Code Section XI 1980 Edition, Winter 1981 Addenda, IWF-3410.

The May 13, 1986 submittal also contained a commitment for an augmented PSI examination of 2-inch-and-smaller miscellaneous branch connections and socket welds in the break exclusion zone (BEZ). This commitment was incorporated in Section 6.6.8 of the FSAR, Amendment 13, dated January 1987. The augmented examination commitment, as described in this submittal and in the revised FSAR, is as follows:

> All nonexempt welds located between the containment wall, outside the containment, and the main steam valve house wall consisting of only the main steam and feedwater lines in the main steam valve house; all high energy branch lines within the mainsteam valve house up to the first relief or nonmanual isolation valve; and those lines identified as "extended" break exclusion zone piping are examined using volumetric techniques on all circumferential butt or longitudinal welds. The above described welds will be 100% volumetrically examined during each inspection interval. Miscellaneous branch connections and socket welds, 2 inch and smaller, will receive a surface examination. The socket welds selected for examination will be limited to a representative 10% sample of the socket weld population.

In the letter dated April 13, 1987, the applicant discussed the use of fabrication visual examination results of Class 3 support integrally welded attachments to satisfy the ASME Code Section XI requirements for PSI. ASME Code Section XI, paragraphs IWB-2200 (Class 1) and IWC-2200 (Class 2), permit shop and field examinations to serve in lieu of onsite preservice examinations, provided applicable criteria are met. IWD-2100 (Class 3) does not provide similar guidance. Additionally, acceptance standards for Class 3 visual (VT-3) examinations, IWD-3000, are in the course of preparation and guidance is not provided elsewhere in ASME Code Section XI. In such cases, IWA-3100(b) references the construction code for the applicable acceptance standards. In a telephone conference on March 26, 1987, the staff concurred that the use of results of visual examination of construction in this application is an acceptable alternative for the PSI visual examinations of Class 3 support integrally welded attachments.

Requests for relief from the ASME Code Section XI requirements which the applicant has determined to be impractical for Class 2 and Class 3 systems and components were received in submittals dated March 12 and April 6, 1987. All of the relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and concluded that in all cases, except the request for relief from the preservice volumetric examination of the reactor coolant filter and seal water heat exchanger welds (for details see Section III.G in Appendix R to this report), the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

Considering its review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that, with the exception of the relief request for the preservice volumetric examination of the reactor coolant filter and seal water heat exchanger welds as identified above, the preservice inspection program for the Class 2 and Class 3 components at Beaver Valley Power Station, Unit 2 is acceptable and in compliance with 10 CFR 50.55a(g)(2). The detailed evaluation supporting this conclusion is provided in Appendix R to this report. The evaluation contained in this section, Section 5.2.4.3, and Appendix R closes open issue 4(a).

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7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Trip System

7.2.2 Specific Findings

7.2.2.3 Design Modification for Automatic Reactor Trip Using Shunt Coil Trip Attachment

In the SER, the staff stated that the installation of the shunt coil trip attachment will be treated as a confirmatory issue. By letter dated April 24, 1987, the applicant informed the staff that the subject installation was completed by Field Change Notice DMWM-10610. This is responsive to the staff's concern and confirmatory issue 26 is considered closed.

The other issue identified in Section 7.2.2.3 of the SER is NUREG-1000, Section 4.3, "Automatic Actuation of Shunt Trip Attachment." That issue continues to be tracked by licensing action TAC 62950. (See also Section 15.8 of this report.)

7.3 Engineered Safety Feature Systems

7.3.2 ESF and EAS System Operation

7.3.2.1 Emergency Core Cooling System

In SER Section 7.3.2.1, the staff indicated that approximately 24 hours after a loss-of-coolant-accident (LOCA) occurrence, the operator manually aligns emergency core cooling system (ECCS) valves to effect a hot-leg recirculation ECCS cooling mode. In FSAR Amendment 13 (Table 6.3-7), the applicant changed the time specification for this alignment to approximately 14 hours, reflecting updated plant-specific analyses. By letter dated July 25, 1986, the applicant identified that Westinghouse had performed the analysis for Beaver Valley 2 and that the 14-hour value is specified in the Beaver Valley Unit 2 Emergency Operating Procedures (staff review of the Beaver Valley Unit 2 Procedures Generation Package is discussed in Section 13.5.2 of this supplement). The Westinghouse calculational technique for this analysis has been approved for other Westinghouse plants and is acceptable for this application. The staff, therefore, finds the 14-hour time designation for alignment to hot-leg recirculation acceptable.

7.3.3 Specific Findings

7.3.3.9 Control Room Isolation on High Radiation Signal

In SSER 1, the staff stated that the applicant had included control room isolation on a high radiation signal as part of the plant design and that completion of the staff's review of the design as documented in the applicant's April 1, 1986, submittal was pending. The review was tracked as a confirmatory issue.

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During a May 6, 1986 meeting with the staff, the applicant provided additional design documentation, and the applicant's letters dated October 16, 1986 and March 9, 1987 provided information in response to staff requests. Additionally, in a meeting held on April 30 and May 1, 1987, the applicant provided further discussion and final design documentation.

During the staff's review of the control room isolation design and related technical specifications, a concern arose over the deliberate isolation of the control room bottled air system during actuation relay testing. The concern was related to the use of local, hand-operated valves to render the system inoperable without an automatic input into the plant's bypassed and inoperable status panels. In response to this concern, the applicant committed to manually activate the associated system bypass indicators in Units 1 and 2 when the bottled air system is deliberately rendered inoperable for relay testing, and to implement appropriate verification procedures to ensure that the system is restored to operable status upon completion of testing. The staff finds this acceptable and considers the concern fully resolved. Also, the staff has reviewed the information provided and finds that the design of control room isolation on high radiation signal is acceptable. On this basis, the staff considers confirmatory issue 46 closed.

7.3.3.12 Steam Generator Level Control and Protection

In the SER, the staff stated that the design for feedwater isolation on a high steam generator level did not satisfy the requirements of Paragraph 4.7 of IEEE Standard 279 because failure of the level channel used for control could require protective action and the remainder of the protection system channels did not satisfy the single-failure criterion. The applicant's position was that 10 CFR 50.55a(h) (which codifies the requirements of IEEE-279 for protection systems) was not applicable to feedwater isolation of a high steam generator level, which the applicant considered as a nonprotective function. In SSER 2, the staff stated that revisions to the FSAR were required to clarify and support the applicant's position. That issue was tracked as confirmatory issue 49. The staff requested additional information by a letter dated February 20, 1987.

In lieu of providing the required FSAR revisions, the applicant (in a letter dated March 4, 1987) proposed a modification to the feedwater control system intended to resolve this issue. This modification would consist of adding a median selector device to each steam generator feedwater control system to select the middle signal from the three existing protection system level channels (through safety-grade isolators). This is consistent with what the staff stated in the February 20, 1987 letter. The applicant has proposed to install this modification by the end of the first refueling outage and has requested a schedular exemption to 10 CFR 50.55a(h) for the operating license for the period of operation before completing the installation.

The staff finds that the proposed installation of a median selector will bring the design for feedwater isolation on a high steam generator level into conformance with the requirements of Paragraph 4.7 of IEEE-279 and will fully resolve the concern of confirmatory issue 49.

The staff believes the schedular exemption for the period of operation before completion of the modification should be granted on the basis of the justification provided in paragraphs (1), (2), (3), and (4) in Section 7.3.3.12 of the SER, reproduced below:

(1) The event of concern, a failure in the control channel leading to a steam generator overfill, should be a relatively small probability because at least two failures in the control channels must occur before the event can occur. Given that the feedwater control system is in automatic, the first failure must be in the steam generator water level channel that is providing input to the control system. It must fail low. The second failure must be on the same steam generator in one of the other two remaining channels, and the failure must be a fail-as-is. A third failure may be involved because the operator is not credited with taking any action. Actually, at 100% power, analysis indicates that there are 10 minutes for operator action and this meets the staff position.

(2) Prior experience on Unit 1 has shown that an operator has been trained to be quite sensitive to steam generator feedwater control problems and is expected to be prompt in correcting any feedwater mismatch because the actions an operator would need to take to intervene and stop this event are quick and easy.

(3) On the basis of the history of overfill events of Westinghouse steam generators, no overfill events occurred as a result of control system failures.

(4) In the intermediate power level range, the range in which operators have the shortest time to act to prevent a steam generator overfill, the applicant noted that the plant will operate less that 2% of the time at these intermediate power levels. During this period, the applicant's present mode of operation requires at least one operator at the feedwater control panel.

The applicant's letter of March 4, 1987 represents a change in design objective. Earlier, the applicant attempted to revise the FSAR so as not to consider the steam generator high-level trip as part of the reactor protection system. When this objective was changed, the applicant immediately commenced design and procurement of the median selector, and has even considered installing it before a license is issued.

The applicant requested the schedular exemption, however, since it may be impossible to install the median selector because of the many activities that must take place before fuel load. On this basis, the staff considers that the applicant has made good-faith efforts to comply with the subject regulation. This satisfies 10 CFR 50.2(a)(2)(v) for granting a schedular exemption.

7.3.3.13 IE Bulletin 80-06 Concerns

In the SER, the staff stated that the applicant's response and review to comply with IE Bulletin 80-06 revealed that all safety-related components (including those that required modification) remained in their safety state after the engineered safety features actuation system logic had been reset. On that basis,

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the staff found the applicant's design in compliance with the requirements of IE Bulletin 80-06 and considered the issue resolved subject to confirmation that a test was completed to verify that the actual installed instrumentation and controls were also in compliance.

Some of the tests required by IE Bulletin 80-06 are to be performed as part of startup tests, i.e., after issuance of a low-power license. The staff will report completion of all tests in a future document. Confirmatory issue 28 remains open.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.1 Emergency Response Capability, RG 1.97, Revision 2, Requirements

In Supplement 1 to the SER in regard to the RG 1.97 variables accumulator level and pressure, the staff stated that the applicant should designate either level or pressure as the key variable to determine accumulator discharge and should provide instrumentation for that variable meeting the requirements of 10 CFR 50.49 (environmental qualification). The staff further stated that the applicant shall install and have operational qualified accumulator tank level or pressure instrumentation at the first scheduled outage of sufficient duration but no later than startup following the first refueling outage (proposed license condition 1, Table 1.5).

In a March 3, 1986 letter, the applicant provided supplemental information on the accumulator tank level and pressure variables. Subsequently, the staff began a generic review of the need for environmental qualification of these variables. This review includes the applicant's position on this issue. When the generic review process is complete, the Beaver Valley Unit 2 accumulator level and pressure instrumentation will be subject to whatever provisions would result from that generic review. In the interim, the existing accumulator level and pressure instrumentation is acceptable, and proposed license condition 1 is deleted.

7.5.2.4 Bypass and Inoperative Status Panel

In the SER, the staff stated that the applicant had committed to include information in the FSAR demonstrating that the design of the Beaver Valley Unit 2 bypass and inoperable status panel conforms with RG 1.47. In FSAR Amendments 7, 11, and 13, the applicant revised Section 7.5.5 to include the required information.

Additionally, in the SER, the staff stated that the applicant had committed to modify two systems to eliminate its concern that bypassing a support system may not lead to a bypass indication for a protection system whose operation depends on the supporting system. The applicant, in a letter dated May 19, 1987, stated that the these modifications were complete.

The staff has reviewed the revised information in FSAR Section 7.5.5 and the information on the installation of the modifications and concludes that confirmatory issue 30 is closed.

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

7.6.2.2 Reactor Coolant System Loop Isolation Valve Interlocks.

In the SER, the staff stated that operation with N-1 reactor coolant system (RCS) loops (i.e., two loops) would be pursued as part of the Technical Specifications review. N-1 loop operation is not proposed at this time; the Technical Specifications will appropriately address N-1 loop operation in accordance with what the staff stated in SER Section 4.4.6.

7.7 Control Systems

7.7.2 Specific Findings

7.7.2.3 Control System Failure Caused by Malfunctions of Common Power Source or Instrument Line

In the SER, the staff stated that the applicant had committed to conduct a thorough review of control system failures at Beaver Valley Unit 2 caused by malfunctions of common power sources or instrument lines similar to reviews performed for other Westinghouse plants. On the basis of that commitment, the staff considered this issue a confirmatory issue pending submittal of satisfactory documentation for review.

In a letter dated October 15, 1985, the applicant documented the results of the review which identified power sources, sensors, or sensor impulse lines that provide power or signals to two or more control systems. The effects of the failures of each of these power sources, sensors, or sensor impulse lines were analyzed. The analysis was conducted for all five major nuclear steam supply system (NSSS) control systems: (1) reactor control system, (2) steam dump system, (3) pressurizer pressure control system, (4) pressurizer level control system, and (5) feedwater control system. The initial conditions for the analysis were assumed to be anywhere within the full operating power range of the plant (0-100%) where applicable.

During the staff's review of the analysis, an issue was raised about the effects of multiple feedwater control valves failing open as a result of a single failure versus the single valve failing open in Chapter 15 of the FSAR. The applicant provided additional information related to this issue in letters dated May 28, 1986 and April 7, 1987.

The results of the analysis indicated that for any of the postulated events considered--including (1) loss of any single instrument, (2) break of any single common instrument line, and (3) loss of power to all systems powered by a single power supply (i.e., single inverter)--the Condition II accident analyses given in FSAR Chapter 15 are bounding. The staff has reviewed the applicant's responses and finds them acceptable. Confirmatory issue 32 is considered closed.

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8 ELECTRIC POWER SYSTEMS

8.3 Onsite Power Systems

8.3.1 Onsite AC Power System's Compliance With GDC 17

8.3.1.1 Voltage Analysis

In the SER, the staff provided the results of its review of the applicant's Beaver Valley Unit 2 voltage and load analysis that was performed in accordance with Position 3 of Branch Technical Position (BTP) PSB-1. The staff stated that with respect to Position 4 of BTP PSB-1 it would verify the test results that substantiate the applicant's analysis. By letter dated April 24, 1987, the applicant provided the results of the voltage verification test that was performed on the Beaver Valley Unit 2 distribution system. Bus voltage measurements were taken on a string of busses from the offsite power source to the 120-V bus level at a minimum 30% loading level. The measurements were made for the steady-state condition as well as for transient conditions during starting of both a large Class 1E and non-Class 1E motor. The measured bus voltage levels were then compared to analytically derived bus voltage levels that were calculated using the same set of initial conditions. The results indicate that the measured voltages are no more than 1.66% (steady state) and 1.66% (transient) below the analytically derived voltages. The maximum voltage difference measured was 2.35% above the analytically derived voltage on a 120-V power panel. These values are less than the maximum value of 3% allowed by Position 4 of BTP PSB-1. Also, when the test results are used to modify the original voltage analysis, the resulting voltage levels are never less than the minimum required voltage for Class 1E equipment. The staff therefore considers the verification test results to be satisfactory. This resolves confirmatory issue 34.

8.3.1.6 Diesel Generator Loading Above Its Continuous Rating

In Amendment 11 to the FSAR, the applicant stated that the worst-case loading imposed on the diesel generator is 3997 kW. This loading is less than the previously stated value of 4211 kW in the SER. The new worst-case loading imposed on the diesel does not exceed the continuous rating of the machine as specified in FSAR Section 8.3.1.1.15. Therefore, the staff finds the FSAR revision acceptable.

8.3.3 Common Electrical Features and Requirements

8.3.3.1 Compliance With GDC 2 and 4

8.3.3.1.1 Submerged Electrical Equipment as a Result of a Loss-of-Coolant Accident

In the SER, the staff stated that by letter dated October 10, 1984 the applicant indicated that all Class 1E equipment with the potential for being submerged as a result of a loss-of-coolant accident (LOCA) is electrically tripped

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by a high flood level indication. Subsequent to this, in FSAR Amendment 13, the applicant has identified a different approach to resolving this issue in its revised response to staff question 430.18.

In its revised response, the applicant has taken the listing of safety-class equipment which may become submerged as a result of a LOCA and has divided the equipment into three groups. Group 1 consists of that equipment which is not required to operate post-LOCA. The applicant stated that the failure position of equipment in this group will not affect a station's LOCA mitigation capability. Group 2 consists of that equipment which accomplishes its post-LOCA function before potential submergence. The applicant stated that it has made an evaluation to ensure that equipment in this group will not operate spuriously when submerged, or that spurious operation will have no adverse impact on shutdown capability. An item in this category, motor-operated valve 2CHS*MOV 310, is tripped off the 1E bus on high containment water level to preclude the possibility of spurious actuation. Group 3 consists of that equipment which has a post-LOCA function and is designed and qualified for submergence.

On the basis of the information provided above for the three groups of equipment, the staff concludes that flooding of this equipment will not prevent the performance of a safety function nor cause a spurious operation that will have an adverse impact on a safety function.

Also, in its revised response to question 430.18, the applicant stated that the design of the Class 1E distribution system provides double-series circuit protection for all power and control circuits which will penetrate the reactor containment. The applicant stated that this redundancy will ensure the Class 1E busses are not degraded by the potential adverse effects of equipment submerged as a result of a LOCA. In SER Section 8.3.3.7.2, the staff evaluated the adequacy of the double-series circuit protection for protection of electrical penetrations. In that section the staff stated that by letter dated August 26, 1985, the applicant proposed to perform periodic testing and calibration for penetration protective devices as a part of the requirement of Regulatory Guide (RG) 1.63. The staff finds that the double-series circuit protection for electrical penetrations that is periodically tested and calibrated (not required for fuses) is also adequate to protect the Class 1E busses against the potential adverse effects of equipment submerged as a result of a LOCA.

8.3.3.3 Physical Independence--Compliance With GDC 17

8.3.3.3.2 Separation of Containment Electrical Penetrations

In Section 8.3.3.3.2 of the SER, the staff evaluated the separation of containment electrical penetrations at Beaver Valley Unit 2. The staff found acceptable the minimum vertical and horizontal separation criteria of 4 feet between related channels, and 8 feet between redundant trains and between train and channel both inside and outside containment. Subsequently, in Amendment 13 to Section 8.3.1.1.16 of the FSAR, the applicant stated that two nuclear instrumentation system triaxial penetrations, 2 RCP*21E (white) and 2 RCP*06B (blue), deviate from the spatial separation criteria identified above. The separation is 4 feet between the respective train and channel. The staff finds that this deviation from the electrical penetration separation criteria that is limited to only these two electrical penetrations is acceptable on the basis that the cables to the electrical penetrations still meet the separation criteria for cables specified at Beaver Valley Unit 2.

8.3.3.3.16 Use of Double-Series Circuit Protection Between Non-Class 1E Loads and Class 1E Power Supplies

In Section 8.3.3.7.2 of the SER, the staff evaluated the adequacy of double-series circuit protection for protection of electrical penetrations. In Section 8.3.3.1.1 of this supplement, the staff evaluated the adequacy of double-series circuit protection to protect the Class 1E busses against the potential adverse effects of equipment submerged as a result of a LOCA. In both of these cases, the double-series circuit protection was found acceptable.

In Amendment 15 to FSAR Table 8.3-2, the use of double-series circuit protection was added as a means of providing isolation of non-Class 1E loads supplied from Class 1E busses. As justification, Table 8.3-2 references the applicant's discussion provided with respect to Paragraph C.1 of RG 1.75 contained in FSAR Table 1.8-1, where it is stated that two independent Class 1E overcurrent devices (breaker or fuses) in series are used to provide electrical separation between Class 1E and non-Class 1E circuits under the following conditions:

(1) Coordination is provided between each of the two series devices and the main Class 1E feeder breaker.

(2) These devices are included in a surveillance program during normal plant operation.

By providing coordination between the two series overcurrent devices and the main Class 1E feeder breaker, assurance is given that at least one of the two series overcurrent devices will clear a fault of a non-Class 1E load before it can damage the Class 1E power source or trip the power source feeder breaker. Including the devices in a surveillance program will ensure that they retain their correct ripping characteristic and coordination. Although the use of overcurrent devices does not meet the specific recommendations of RG 1.75 for isolation devices, the staff finds that the double-series circuit protection, together with the above provisions, offer an acceptable alternate means of providing protection of the Class 1E power supplies.

8.3.3.7 Compliance With GDC 50

8.3.3.7.1 Description and Analysis of Compliance With GDC 50

In Section 8.3.3.7.1 of the SER, the staff stated that by Amendment 3 to the FSAR, the applicant provided a description with the results of testing and analysis to show compliance with GDC 50. On the basis of this information, the staff considered this item resolved pending documentation of the description and analysis in FSAR Section 8.0. There now exists in Section 8.3.1.1.16 of the FSAR (Amendment 16) a description of the electrical penetration assemblies, their locations, and the specifications they are designed, manufactured, and tested to. This information closes confirmatory issue 35.

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9 AUXILIARY SYSTEMS

9.3 Process Auxiliaries

9.3.2 Process and Post-Accident Sampling Systems

9.3.2.2. Post-Accident Sampling System (NUREG-0737, Item II.B.3)

In the SER, the staff concluded that the post-accident sampling system met ten of the eleven criteria of Item II.B.3 in NUREG-0737. The staff stated that the applicant should provide a procedure for estimating the extent of reactor core damage. The applicant was expected to provide a plant-specific procedure for estimating the extent of core damage based on the Westinghouse Owners Group methodology, before fuel load.

Criterion (2) of Item II.B.3 in NUREG-0737, the remaining criterion to be satisfied, states:

> The applicant shall establish an onsite radiological and chemical analysis capability to provide, within the three-hour time frame established above, quantification of the following:
>
> (a) Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g. noble gases, iodines and cesiums, and non-volatile isotopes);
>
> (b) hydrogen levels in the containment atmosophere;
>
> (c) dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids;
>
> (d) Alternatively, have in-line monitoring capabilities to perform all or part of the above analyses.

By letter dated April 13, 1987, the applicant provided a plant-specific procedure for estimating the degree of reactor core damage, based on the methodology developed by the Westinghouse Owners Group. The approach used in this procedure will take into consideration measurements of fission-product concentration in the primary coolant system and containment atmosphere. The radionuclide measurements, together with readings from core exit thermocouples, water level indicators in the reactor vessel, containment radiation monitors, and containment atmospheric hydrogen analyzers, will be used to obtain a weighted assessment of various levels of fuel damage. The staff concludes that these provisions meet Criterion 2 of Item II.B.3 in NUREG-0737, and are acceptable. Accordingly, confirmatory issue 36 is considered closed.

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9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

In Supplement 3 to the SER (SSER 3), the staff reviewed fire protection information through Amendment 12 to the FSAR. Following this review, four unresolved issues remained: open issue 5, safe and alternate shutdown; backfit issue 7, cable spreading room fire protection; and confirmatory issues 48(b) and (c) relating to the separation of safe shutdown components, and tracking concerns for backfit issue 7, respectively.

After SSER 3 was issued, the applicant incorporated the Fire Protection Evaluation Report into Amendment 14 to the FSAR as Appendix 9.5A. This amendment significantly revised the applicant's fire protection program and identified deviations in many areas not previously addressed. The present supplement (SSER 5) includes an evaluation of new deviations identified in Amendment 14 and information provided by the applicant regarding the four open issues as well as new information provided in Amendment 17 of the FSAR. SSER 5 also addresses concerns raised during a site audit conducted January 27-30, 1987.

9.5.1.4 General Plant Guidelines

Branch Technical Position (BTP) CMEB 9.5-1, Section C.5.a(1) states that fire barriers with a minimum fire resistance rating of 3 hours should be provided to "separate safety-related systems from any potential fire in nonsafety-related areas that could affect their ability to perform their safety function" and to "separate redundant divisions or trains of safety-related systems from each other so that both are not subject to damage from a single fire."

In Amendment 14, the applicant stated that the structural steel supporting the 3-hour fire-rated walls that separate the 780-foot, 6-inch elevation of the service building (Fire Area SB-5) from the turbine building and the 773-foot, 6-inch elevation of the auxiliary building (Fire Area PA-5) from the turbine building and the health physics area have not been fireproofed. The staff was concerned that a fire in the turbine building or in the upper elevations of the service or auxiliary building could cause the steel to collapse, jeopardizing safe shutdown equipment in the surrounding areas. However, Appendix 9.5A to the FSAR demonstrates that the loss of safety-related equipment in areas adjacent to the unprotected steel would not affect the plant's ability to achieve a safe shutdown. In addition, Table 3.2.2 of the applicants FSAR states that the floor slabs at the 773-foot, 6-inch and the 780-foot, 6-inch elevations, which are the fire boundaries directly below the unprotected steel in the service and auxiliary buildings, are rated as seismic Category I. Section 3.6.B1.3.4.3 of the FSAR states that if non-seismic Category I portions of the structural fail, no adverse effects on adjacent seismic Category I structures or components will occur. Therefore, if a fire caused the unprotected structural steel to collapse, the plant would still be able to achieve a safe shutdown. Considering this evaluation, the staff concludes that the lack of structural steel fireproofing in Fire Areas SB-5 and PA-5 does not adversely affect plant safety and is an acceptable deviation from Section C.5.a(1) of BTP CMEB 9.5-1.

In the SER, the staff stated that the applicant would provide qualified penetration seals for all penetrations of fire-rated walls or floor/ceiling

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assemblies. In Amendment 14 to the FSAR, the applicant stated that because of installation problems, certain fire barrier penetrations could not be sealed per Section C.5.a(3) of BTP CMEB 9.5-1. The applicant identified approximately 18 penetrations, of 4-inch diameter or greater, which cannot be sealed at the barrier. The applicant proposed to seal these penetrations with fire-seal material at the first opening and wrap the conduit from the seal to the barrier with 1-hour fire-wrap material. Seventeen of the penetrations have detection and automatic suppression on both sides of the barrier. The remaining penetration has detection on both sides with automatic suppression on one side. The applicant also stated that certain penetrations throughout the plant which are less than 4 inches in diameter and extend less than 5 feet on either side of the barrier cannot be sealed at the barrier. For these cases, the applicant proposed to seal the penetration at the first opening on both sides of the barrier with a fire-seal material. During the site audit on January 27-30, 1987, seals of both configurations were reviewed in the field and were found to provide an adequate measure of sealing for penetrations in fire barriers when the Standard Review Plan (SRP) (NUREG-0800) cannot be met because of installation difficulties. Therefore, the method for sealing penetrations as identified in Amendment 14 to the FSAR is an acceptable deviation from Section C.5.a(3) of BTP CMEB 9.5-1 when installation difficulties do not allow for sealing at the barrier.

In SSER 3, the staff stated that some fire damper assemblies were located outside of the fire barrier because of a redefining of certain fire areas and that where this took place, the ductwork from the barrier to the fire damper assembly would be wrapped with 3-hour fire-rated material. Section C.5.a(4) of BTP CMEB 9.5-1 states that, "penetration openings for ventilation systems should be protected by fire dampers having a rating equivalent to that required of the barrier." In a meeting on November 5, 1986, the applicant stated that 3-hour wrap material could not be used because of weight limitations of the structural supports and stated that the ductwork would be wrapped with 1-hour rated material. This deviation was included in Amendment 14 to the FSAR following the meeting. Fire dampers requiring 1-hour wrap are used as fire barriers between Fire Areas PA-3 and PA-5, PA-4 and PA-5, SB-3 and SB-4, SB-4 and SB-5, and PT-1 and SG-1S. The fire loading is less than 1/2 hour on either side of the subject dampers. Smoke detection is provided in all areas where the 1-hour wrap will be installed and hose racks are provided for fire brigade use. It is expected that a fire would be detected in its incipient stage and the plant fire brigade would extinguish it using the installed hose racks. Providing additional structural support to the ductwork to accommodate 3-hour wrap would not significantly increase the level of fire safety. Therefore, wrapping ductwork from the barrier to the damper with 1-hour material is an acceptable deviation to Section C.5.a(4) of BTP CMEB 9.5-1.

The applicant also identified one damper in Fire Area SB-4 in which a 2-inch portion of the ductwork could not be wrapped because of interferences and therefore constituted an additional deviation from Section C.5.a(4) of BTP CMEB 9.5-1. The fire loading in this area is less than 1/2 hour and detection is provided. The 2-inch portion of the ductwork is above one of the 1-1/2 hour dampers that are in series. Lack of wrap on this 2-inch ductwork section does not adversely affect plant fire safety and therefore, is an acceptable deviation from Section C.5.a(4) of BTP CMEB 9.5-1.

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The applicant stated in Amendment 14 to the FSAR that ventilation ductwork for the battery room exhaust system and the emergency switchgear ventilation system pass through areas not serviced by the two systems. To ensure the operability of these systems in the event of a fire in an area not using these systems, the ductwork was wrapped with 1-hour material in areas not serviced by the ventilation systems. Battery room exhaust ducts run through Fire Areas SB-1, SB-2, and SB-4. Each of these areas has a fire loading of less than 1 hour and detection is provided. In the event of a fire in these areas, it is expected that the fire would be detected in its incipient stage and that the plant fire brigade would respond and extinguish the fire. Both the battery room exhaust ductwork and the emergency switchgear ventilation ductwork run through Fire Areas CV-1, CV-3, and SB-3. These fire areas have a combustible loading of less than 2 hours and are provided with detection and automatic suppression. It would be expected that a fire in these areas would be detected in its incipient stage and that the plant fire brigade would respond and control it. The automatic suppression provides added assurance that a fire would not jeopardize the integrity of the 1-hour wrapped ventilation ducts. On the basis of this evaluation, this method of ensuring continuous ventilation to the battery room and emergency switchgear is acceptable.

In the SER, the staff stated that with the exception of two rolling fire doors, door openings are in compliance with Section C.5.a(5) of BTP CMEB 9.5-1, which states that "door openings in fire barriers should be protected with equivalently rated doors, frames, and hardware that have been tested and approved by a nationally recognized laboratory." The applicant stated in Amendment 14 to the FSAR that certain doors have been modified by the installation of security hardware and are no longer approved fire doors. The applicant also stated that there are "special purpose" doors that are not approved by Underwriters Laboratories (UL). During the site audit of January 27-30, 1987, the applicant identified 40 doors that were modified for security purposes. The applicant demonstrated that all modifications were made in accordance with recommendations supplied by UL. Although the applicant stated that all doors were originally purchased as UL-approved, it was noticed during the site visit that some UL labels were missing from doors. The applicant committed to have the doors relabeled by the manufacturer or to maintain on file documentation that individual doors are UL approved. This commitment will be implemented by fuel load. It was also observed that the security modifications consisted primarily of the addition of electric contact switches with a single conduit penetrating the frame. Installations appeared to be in accordance with design drawings, which were based on UL recommendations. Therefore, with the exception of the doors missing labels, the security-modified fire doors are an acceptable deviation from Section C.5.a(5) of BTP CMEB 9.5-1.

During the audit, the applicant also stated that the containment access hatch did not contain a UL label or certification of fire testing. The hatch was observed to be similar to air locks used at other facilities and was designed to meet multiple accident criteria. The combustible loading near the hatch is low; therefore, there is reasonable assurance that a fire of significant magnitude or duration will not occur near the air lock. If a fire does occur, it is probable that the substantial construction of the air lock will prevent fire propagation through the containment boundary. Therefore, an unrated containment access hatch is an acceptable deviation from Section C.5.a(5) of BTP CMEB 9.5-1.

In the SER, the staff identified two rolling steel fire doors as acceptable deviations from the SRP. In Amendment 14 to the FSAR, the applicant identified a third rolling door between the turbine building and the south office shops building as an additional deviation. This door was originally purchased and installed as an unrated exterior door and later became an interior door when the office building was added. There are minimal combustibles in the area of this door and automatic sprinklers have been provided on both sides. A fire on either side of the door would not compromise the ability of the plant to achieve a safe shutdown. Therefore, the unrated rolling door between the turbine building and the south office shops building is an acceptable deviation.

In the SER, the staff stated that the main service transformers are located more than 50 feet away from any building or are separated by 3-hour walls, and that the station service transformers are located within 50 feet of the turbine building; however, no safety-related equipment is located within the turbine building. The applicant stated in Amendment 14 to the FSAR that four transformers, TR-2A, TR-2C, TR-2D, and TR-MT-2, are located within 50 feet of buildings which do not have a fire-resistance rating of at least 3 hours. This is a deviation from Section C.5.a(13) of BTP CMEB 9.5-1. The applicant stated that all walls within 50 feet of the transformers are 2-hour rated and that all four transformers are provided with automatic deluge systems. In addition, the fire hazards analysis identifies safety-related station air compressors in the turbine building; however, they are not required for the safe shutdown of the plant. Therefore, the transformers do not pose a fire threat to plant safety, adequate separation and protection has been provided, and the configuration of the four transformers is an acceptable deviation from BTP CMEB 9.5-1.

Fire Protection of Safe and Alternate Shutdown Capability

In Section 4.5.1.4 of the SER, the staff stated that its review of safe and alternate shutdown capability would be addressed in a supplement to the SER. Since then, the applicant has provided a fire protection safe shutdown report (FPSSR) in accordance with the guidance of SRP Section 9.5.1 and Positions C.5.b and C.5.c of Branch Technical Position (BTP) CMEB 9.5-1. Further discussions of the safe and alternate shutdown capability including information on cable separation and safe shutdown equipment is contained in FSAR Sections 7.4 and 9.5.1.

Safe Shutdown Capability

The staff review of the fire protection afforded the safe shutdown capability of Beaver Valley Unit 2 included the FSAR, up to and including Amendment 16, the fire protection safe shutdown report (FPSSR) provided by transmittal dated March 24, 1987 and additional information provided by letter dated May 11, 1987. FSAR Section 9.5.1 describes the overall fire protection program and the FPSSR discusses the safe shutdown capability, including the potential for spurious operation of equipment in each fire area. FSAR Section 7.4 provides additional information on safe and alternate shutdown system controls capability.

The applicant's safe shutdown analysis demonstrates that systems needed for hot and cold shutdown are redundant and that one of the redundant systems needed for safe shutdown would be free of fire damage because of separation,

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fire barriers, fire detection and suppression, or a combination of these, and/or alternative shutdown capability. Alternative shutdown capability is provided for a fire in the instrumentation and relay room (CB-1), cable spreading room (CB-2), main control room (CB-3), west communication room (emergency shutdown panel station) (CB-6), and cable tunnel (CT-1) because these areas contain more than one division of safe shutdown cabling in close proximity to each other and in-place protection from fire cannot be provided.

For hot shutdown and for cooldown to cold shutdown conditions, at least one train of the following safe shutdown systems would be available: reactor coolant system (RCS), auxiliary feedwater system, main steam system (atmospheric dump valves) and chemical and volume control system (CVCS). For cold shutdown conditions, at least one train of the residual heat removal (RHR) system would be available for long-term decay heat removal. A single train provides the capability to achieve cold shutdown conditions within 72 hours with or without offsite power after a fire. The availability of these systems includes the components, cabling, electrical distribution panels, and support systems necessary to achieve cold shutdown. The support systems include the service water system; reactor plant component cooling water system; emergency diesel generator and its support systems; station service air system; filter water system; necessary heating, ventilation, and air conditioning systems; emergency ac and dc power systems; and necessary instrumentation to monitor plant parameters for safe shutdown. The above systems are used to achieve safe shutdown through various success paths, depending on the location of the fire. Reactivity control is accomplished through control rod insertion followed by boration provided by a charging pump (CVCS) drawing suction from borated water supplies from the refueling water storage tank or from the boric acid tanks through a boric acid transfer pump. RCS makeup/inventory control is provided by a charging pump combined with letdown. RCS pressure control is also accomplished by a charging pump combined with letdown, the power-operated relief valves, or the pressurizer heaters if available. RCS decay heat removal is accomplished initially using the steam generator safety relief valves and by the power-operated relief valves (atmospheric dump valves) during cooldown, and the auxiliary feedwater system, down to a temperature of 350°F, at which time the heat-removal function is transferred to the RHR system.

For certain fires outside the control room, cold leg temperature (T-cold) wide range indication may be lost because all T-cold indication in the control room is powered from train B. This is acceptable since alternate means for determining T-cold is available by use of steam generator pressure indication and other normal train A primary system instrumentation. Similarly for certain other fires outside the control room, the use of core exit thermocouples for T-hot indication and use of T-cold as an alternate to steam generator pressure indication are acceptable.

The applicant's fire protection safe shutdown analysis demonstrates that except for the instrument and relay room (CB-1), cable spreading room (CB-2), main control room (CB-3), west communication room (CB-6), and cable tunnel (CT-1), redundant systems and cabling needed for safe shutdown following a fire are separated in accordance with BTP CMEB 9.5-1, Positions C.5.b.1 and C.5.b.2 with some noted deviations that are evaluated elsewhere in Section 9.5.1 of the SER and its supplements. For Fire Areas CB-1, CB-2, CB-3, CB-6, and CT-1, the applicant has provided alternate shutdown capability independent of these areas in accordance with Position C.5.c of BTP CMEB 9.5-1.

For a fire in some areas, the emergency ventilation system which provides cooling to the charging pump cubicles and component cooling water pump area may be lost because of the close proximity of control cables. The applicant has provided portable ventilation for the charging pump cubicles to be initiated within 24 hours as indicated in heatup calculations for the room to meet equipment qualifications. Additional ventilation for component cooling water pumps is not required because the pumps are in a large open area. The staff finds the use of portable ventilation for the charging pump cubicles acceptable because of the large time period available before the ventilation is needed.

The applicant's fire hazard analysis for each plant area includes an evaluation of the safe shutdown capability given a fire in that particular area. The evaluation identifies which safe shutdown train (A or B) is to be used in the event of a fire in an area. The evaluation also identifies the possible spurious actuations that can occur from a fire in each area. Manual actions to overcome spurious actions or the compensatory measures taken are described in the applicant's fire protection safe shutdown report and in the plant operating manual for fire prevention and control. Compensatory measures include tripping breakers, stopping specific pumps, and opening or closing certain valves as required.

The capability to achieve and maintain hot shutdown conditions is accomplished without repairs. In order to achieve cold shutdown conditions in certain fire areas, some repairs to allow opening of valves in the RHR, component cooling water and service water systems and to permit operation of the PORV block valve may be required. Repairs consist of lifting leads, installing jumpers, and replacing fuses. No replacements of major components or routing of additional cables are required. The indicated repairs are acceptable as they are relatively simple, are not required for hot shutdown, and will ensure that the plant can achieve cold shutdown conditions within 72 hours without additional manpower.

In the applicant's fire protection safe shutdown analysis, cable runs were traced through each fire area from the corresponding safe shutdown components to their power source. Additional equipment and electrical circuitry considered as associated either because of shared common power sources, common enclosures, or where fire-induced spurious operations could affect shutdown were also identified. For the identified associated circuits, the applicant provided circuit isolation and/or procedures to ensure that circuit failures would not prevent safe shutdown. For example, in order to prevent fire-induced spurious signals from causing loss-of-coolant accidents (LOCAs) from sources such as the RHR suction line or PORVs, the following measures are provided. The applicant will lock out power to one of the two series suction line isolation valves during power operation. Similarly, the operator will de-energize the pressurizer PORVs not controlled from the alternate shutdown panel and the reactor vessel head vent valves when using the post-fire alternate shutdown system, thereby preventing any fire-induced spurious actuation of these valves.

In order to ensure that common bus, multiple, high-impedence faults resulting from damage to two or more cables in a fire area will not affect the safe shutdown capability by tripping the main breaker for essential power supplies to safe shutdown equipment instead of individual circuit breakers, the applicant indicated that the operators will be instructed to trip non-required loads and reenergize the bus. This approach will ensure power to safe shutdown equipment.

The staff has reviewed the applicant's safe shutdown systems and methodology for determining that the separation criteria of BTP CMEB 9.5-1, Position C.5.b are met with acceptable exceptions and has also reviewed the associated circuits identified by the applicant and the actions necessary to prevent or correct spurious operations that could affect safe plant shutdown.

On the basis of its review, the staff concludes that the post-fire safe shutdown system and cable separation methodology comply with General Design Criterion (GDC) 3 and the criteria of Appendix R, Section III.G as contained in SRP Section 9.5-1 and BTP CMEB 9.5-1, Position C.5.b and are, therefore, acceptable. This closes the part of open issue 5 regarding safe shutdown.

Alternate Shutdown Capability

The applicant has provided alternate shutdown capability for a fire in the instrumentation and relay room (CB-1), cable spreading room (CB-2), main control room (CB-3), west communication room (CB-6) and cable tunnel (CT-1) via the alternate shutdown panel (ASP), transfer switch panel and local stations outside the above areas. FSAR Section 7.4 and fire protection safe shutdown report Appendix A-2 describes the alternate shutdown panel capability and identifies the instrumentation and control located thereon. The alternate shutdown panel is located at elevation 755 feet, 6 inches in the auxiliary building and control one train (train A) of redundant shutdown components which are necessary for cold shutdown of the plant. Transfer switches isolate the safe shutdown equipment cables from the affected fire areas to ensure independent control of the alternate shutdown panel.

The alternate shutdown capability provides direct reading and controls to monitor the process variables and take the necessary action to perform reactivity control, reactor coolant makeup/inventory control and reactor heat removal. The applicant has provided the following essential indications at the alternate shutdown panel independent of the control room for achieving and maintaining safe shutdown:

(1) pressurizer level
(2) reactor coolant system (RCS) wide-range pressure
(3) RCS wide-range hot-leg temperature
(4) RCS wide-range cold-leg temperature
(5) steam generator wide-range pressure
(6) steam generator wide-range level
(7) auxiliary feedwater flow to two steam generators
(8) source and startup-range reactor flux

The alternate shutdown panel also includes controls for the following essential systems or components:

(1) charging and boric acid pumps
(2) auxiliary feedwater (AFW) pump
(3) residual heat removal (RHR) pump
(4) component cooling water (CCW) pump
(5) service water pump
(6) charging pump flow control valve and suction isolation valve from the RWST
(7) letdown orifice, isolation and coolant recovery valves
(8) AFW flow control valves
(9) atmospheric steam dump valves

(10) pressurizer power operated relief valves
(11) pressurizer heaters
(12) nitrogen supply valves to safety injection accumulations
(13) RHR isolation valves
(14) CCW supply valve to RHR heat exchanger
(15) service water pump discharge valve and supply valve to diesel generator
(16) emergency diesel generator set and supply breakers

Local indications and controls will be used for other components required for shutdown.

The design of the alternate shutdown system complies with the performance goals outlined in Position C.5.c of BTP CMEB 9.5-1. Reactivity control is accomplished by (1) manual scram (before the operator leaves the control room), (2) boron addition via the chemical and volume control system (CVCS) using the refueling water storage tank or boric acid tank, and (3) controlling the RCS letdown. The reactor coolant makeup and pressure control functions are also performed by the charging pump, letdown and RWST. Reactor coolant inventory is ensured by maintaining reactor coolant pump seal injection and by isolating possible locations of inventory loss such as PORVs, RHR suction lines, letdown line and reactor head vents. RCS pressure control is also provided by the PORV or actuation of the pressurizer heaters. Heat is removed from the RCS by the AFW system, main steam safety valves or the power-operated main steam relief valves. When the RCS temeprature falls to 350°F, the heat removal function is transferred to the RHR system. All these operations can be accomplished from outside the control room.

In addition to scramming the reactor from the control room, the applicant has included procedures for other actions that are to be performed before the control room is evacuated. These actions, however can be performed outside the control room regardless of circuit damage within the control room. They include, among other, tripping MSIVs, closing the PORV block valves and letdown isolation valves, and aligning the charging pump suction to the RWST. The above actions will prevent spurious actuations, failure of specific automatic functions, and the operation of other specific automatic functions from causing an unrecoverable condition. The transfer switches are designed so that even if fire damages the circuits before the position of a transfer switch is changed, fuse replacement is not required for equipment operation after the transfer is complete. Thus, the design of transfer switches adequately cover the concern identified in Inspection and Enforcement (IE) Information Notice 85-09, "Isolation Transfer Switches and Post-Fire Safe Shutdown Capability."

The staff has reviewed the actions required by the procedures for achieving and maintaining safe plant shutdown following a control room area fire. For hot standby, the immediate actions are primarily precautionary measures to ensure that no unacceptable spurious actuations take place because of a control room fire. Should they occur before these actions are accomplished, the procedures provide guidance for overcoming and correcting the inadvertent spurious actuations. The procedures also describe other operator actions at the ASP and local stations for safe hot and cold shutdown from outside the control room. Portable ventilation may have to be provided for the charging pump cubicles within 24 hours, as described previously. Repairs for opening the containment isolation valves for the component cooling water and service water systems may be required for cold shutdown. Repairs consist of lifting leads, installing jumpers, and replacing fuses. Component cooling water provides cooling to the RHR heat exchangers. Service water provides cooling water to the containment air recirculation coils for RHR pump room ventilation. Portable ventilation and other materials for repairs are stored in a dedicated area on site. Repair procedures are included in the plant operating procedures. The staff has reviewed the proposed actions and manpower requirements for alternate safe shutdown and concludes they are in accordance with Position C.5.c of BTP CMEB 9.5-1, including the use of portable ventilation for the charging pump cubicles and repairs of valves for cold shutdown, since they can be accomplished exclusive of fire brigade members.

On the basis of its review, the staff concludes that the alternate shutdown capability complies with the requirements of GDC 3 and the criteria of Appendix R, Section III.L as contained in SRP Section 9.5.1, and BTP CMEB 9.5-1, Position C.5.c and is, therefore acceptable. This closes the alternate shutdown part of open issue 5.

Safe Shutdown Components

Section C.5.b of BTP CMEB 9.5-1 identifies the separation criteria for redundant safe shutdown components. The applicant had originally intended to install new barriers for areas that do not meet these guidelines. By letter dated March 27, 1985, the applicant stated that installation of these barriers would not be possible and that an alternative means of separation would be required, which would necessitate deviations from the SRP. Amendment 14 to the FSAR identified 11 areas in which deviations from the separation criteria exist. One of these areas, the charging pump room, was approved in SSER 3. The remaining deviations have been evaluated through Amendment 14 and during a site audit of January 27-30, 1987. The 10 deviations were found to be acceptable as identified in the following evaluations.

Component Cooling Water Pumps

The component cooling water pumps (2CCP*p21A, B, and C) are located in the auxiliary building at elevation 735 feet, 6 inches. Pumps A and B are separated by 24 feet; however, the C swing pump is located between pumps A and B and is an intervening combustible. Each pump contains 1/2 gallon of lube oil and has combustible motor insulation. The combustible loading in the immediate area of the pumps is negligible and there is detection and automatic water suppression over each pump. There is reasonable assurance that a single fire could not jeopardize the operation of both pumps A and B. If a fire were to occur, the plant fire brigade would respond and control it. The automatic suppression would also limit the size and intensity of a fire. Therefore, the lack of at least 20 feet of separation of the component cooling pumps with no intervening combustibles is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Boric Acid Transfer Pumps and Storage Tanks

Each of the boric acid pumps and tanks is located in a separate cubicle with 2-foot-thick reinforced concrete walls. The pumps and tanks do not meet the separation criteria because they are located within 20 feet of their redundant components and the cubicles are not totally enclosed. Each of the cubicles has a labyrinth-type opening for missile and radiation protection. Each cubicle will be provided with detection and the combustible loading is low. It is expected that a fire would be detected in its incipient stage and that the plant fire brigade would respond and control it. It is not probable that a fire in any cubicle could travel through the labyrinth opening and into the adjacent cubicle of the redundant component. Therefore, the arrangement of the boric acid transfer pumps and boric acid storage tanks is an acceptable deviation from BTP CMEB 9.5-1 Section C.5.b.

Charging System Suction Valves

There are four valves that can provide suction paths for the charging pumps during shutdown. All four valves are located in the same area; however, only one valve is necessary for safe shutdown. There is approximately 15 feet of separation between the farthest valves. The combustible loading in the area is negligible. Access to the area will be strictly controlled for radiation purposes and therefore, it is unlikely that transient combustibles would accumulate. The area is provided with detection and it is expected that a fire would be detected in its incipient stage and that the plant fire brigade would respond and extinguish it. There is reasonable assurance that a fire would not prevent the operation of at least one of the four valves. Therefore, the lack of charging system suction valve separation is an acceptable deviation from BTP CMEB 9.5-1, Section C.5.b.

Emergency Switchgear Room Supply and Exhaust Fans and Emergency Switchgear Room Supply Dampers

The emergency switchgear room supply and exhaust fans and emergency switchgear room supply dampers do not meet the criteria of the SRP because the redundant components are not separated from each other by a 3-hour barrier. The two supply fans and two exhaust fans are located in Fire Area CV-4. All of the motors are totally enclosed and are located in separate ductwork. The control cable for supply fan A and exhaust fan A has been protected with 1-hour fire-wrap material in the fire area outside of the ductwork. The combustible loading in the fire area is negligible and detection has been provided. It is anticipated that if a fire were to occur, it would be detected in the incipient stage and the plant fire brigade would respond to extinguish it, using adjacent hose racks. There is reasonable assurance that a fire would not jeopardize both trains of supply fans and exhaust fans. The supply dampers are located in a plenum adjacent to the supply fans. The combustible loading in the plenum is negligible and there is limited access by plant personnel. The damper motors are totally enclosed, which would prevent the burnout of one motor from affecting the operation of the other. There is reasonable assurance that a fire would not affect the operation of both dampers. Therefore, the lack of separation between the emergency switchgear room supply fans and exhaust fans and the emergency switchgear room supply dampers is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Charging Pump Emergency Exhaust Fans

The charging pump emergency exhaust fans are not in compliance with the SRP because they are not separated by a 3-hour barrier. The fans are located in Fire Area PA-4 and are in a configuration similar to the emergency switchgear supply and exhaust fans. Both fans and motors are totally contained within the ductwork. The combustible loading near the fans is low and detection is provided. Therefore, the lack of separation between the charging pump emergency exhaust fans is an acceptable deviations from Section C.5.b of BTP CMEB 9.5-1.

Auxiliary Feedwater Control Valves

The six auxiliary feedwater control valves are all located in Fire Area SG-1S, which deviates from the separation guidelines of the SRP. However, these valves are hydroelectrically operated, normally open valves, which fail "as is" on loss of electrical control. On loss of hydraulic oil, the auxiliary feedwater flow will open the valves. The applicant stated that auxiliary feedwater flow can be controlled by manually throttling the discharge valve at the auxiliary feedwater pump. The combustible loading in fire area SG-1S is less than 1/2 hour and detection is provided. It is anticipated that a fire would be detected early and the plant fire brigade would respond and control it. Even if a fire were to disable all six valves, the plant could still be able to safely shut down. Therefore, the lack of separation between redundant auxiliary feedwater control valves is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Atmospheric Steam Dump Valves and Main Steam Isolation Valves

Atmospheric steam dump valves 2SVS*PCV 101 A, B, and C and main steam isolation valves (MSIVs) 2MSS*HYC 101 A, B, and C are located in the main steam valve house and are not separated in compliance with the SRP guidelines. The combustible loading in the valve house is less than 1/2 hour and detection is provided. The steam dump valves are partially separated by concrete walls, which extend at least 2 feet beyond the valves. The MSIVs are spring-loaded valves, which are latched open during plant operation. Only one of the three solenoid-operated valves for each MSIV is required to operate to close the MSIV. Two of the solenoids are designed to de-energize and the third is designed to energize. There is reasonable assurance that a fire would not prevent the operation of the required steam dump valves or main steam isolation valves. By letter dated December 4, 1986, the staff granted an exemption for the Beaver Valley Unit 1 main steam valve room equipment separation. The configuration of the Unit 2 main steam valve room is equivalent to that of Unit 1. Therefore, the lack of separation between valves in the main steam valve room is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Reactor Containment

Equipment inside containment is not in compliance with Section C.5.b of BTP CMEB 9.5-1 because redundant trains of safe shutdown components and circuitry are not separated by 3-hour walls or are not separated by 20 feet with no intervening combustibles. Generally, redundant cables inside the containment are run on opposite sides of the interior wall. Although this does not provide 3-hour separation, the wall is a significant barrier to fire and heat. Cables inside the containment are either qualified to IEEE Standard 383 or are run inside conduit. The only significant combustible loading other than cable is the oil inside the reactor coolant pumps, RHR pumps, and the charcoal filters. The reactor coolant pumps are provided with an oil collection system in compliance with the SRP, which reduces the potential for spread of combustible oil.

Both the RHR pumps and the charcoal filters are provided with detection and suppression systems. The penetration area, where redundant divisions are separated by at least 18 feet, is provided with detection and automatic suppression. Because of the low in situ combustibles and the containment's large volume, it is expected that any fire would develop slowly with the heat dissipated to the large air space. In addition, because access to the area is tightly controlled, it is not expected that transient combustibles would contribute to the fire loading. Therefore, there is reasonable assurance that a fire inside the containment would not jeopardize both trains of redundant safe shutdown equipment, and lack of complete separation of redundant trains of safe shutdown components inside containment is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Safe Shutdown Circuitry

In Amendment 14 to the FSAR, the applicant identified six fire areas where safe shutdown circuitry is not in compliance with Section C.5.b of BTP CMEB 9.5-1. The fire areas include cable vaults (CV-4 and CV-5), primary auxiliary building (PA-4), pipe tunnel (PT-1), south safeguards building (SG-1S), and the service building normal switchgear (SB-4). These fire areas deviate from the SRP because they do not contain automatic suppression in addition to detection and 1-hour separation. All six areas have a combustible loading of less than 1/2 hour and detection is provided. One train of circuitry is wrapped with 1-hour material in each of the six areas. It is expected that a fire would be detected in its incipient stage and the plant fire brigade would respond. All of the areas are provided with hose racks for fire brigade use. Providing automatic suppression in these areas would not significantly increase the level of fire protection. Therefore, the lack of area suppression for Fire Areas CV-4, CV-5, PA-4, PT-1, SG-1S, and SB-4 is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

Electrical Cable Construction, Cable Trays, and Cable Penetrations

In the SER, the staff identified three fire areas where cable tray separation did not meet the guidelines of Section C.5.e(2) of BTP CMEB 9.5-1. They include the containment (RC-1) and the primary auxiliary building (PA-3 and PA-4). In Amendment 14 to the FSAR, the applicant provided clarification of this deviation and stated that continuous line-type detection was not provided in any safety-related cable trays; however, all areas containing safety-related cables had general area detection and all areas with concentrated cables, except for RC-1, PA-3, and PA-4, were provided with automatic suppression. As identified previously in the SER, the addition of automatic suppression in these three areas would not significantly enhance fire safety. Also, the general area detection provides adequate assurance that a fire in any safety-related cable will be detected in its incipient stage, making line-type heat detection unnecessary. Therefore, the lack of automatic suppression in fire areas RC-1, PA-3, and PA-4 and the lack of continuous-line type of heat detection in safety-related cable trays are acceptable deviations from Section C.5.b of BTP CMEB 9.5-1.

Lighting and Communication

In the SER, the staff stated that fixed, self-contained lighting units with individual 8-hour battery-powered supplies are installed in all areas that will be staffed for shutdown and in all areas for access to and egress from

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all fire areas. In Amendment 14 to the FSAR, the applicant identified a deviation from Section C.5.g(1) of BTP CMEB 9.5-1 because certain yard areas are used for access routes to and from alternate shutdown areas and separate battery-powered lights were not provided. The applicant stated that lighting for these exterior routes is provided by the security lighting system. The security lighting system is powered by a dedicated diesel generator, which operates in the event of a loss of normal power supplied to the security system. The security diesel generator is separate from the main plant and the control room. A fire in any area requiring alternate shutdown will not cause loss of security lighting. The security generator has a sufficient capacity and fuel supply to power the yard lighting for the 8-hour specified time period. The applicant also stated that operators are provided with portable flashlights to enhance the emergency lighting system. There is reasonable assurance that adequate lighting for required yard areas is provided and that the lack of 8-hour battery-powered emergency lighting units in the outside yard areas will not prevent the plant from safely shutting down. Therefore, the use of the security lighting system for outside areas in lieu of battery-powered lights is an acceptable deviation from Section C.5.g(1) of BTP CMEB 9.5-1.

9.5.1.5 Fire Detection and Suppression

Fire Detection

During the site audit on January 27-30, 1987, it was observed that smoke detection was not provided in areas containing the boric acid storage tanks, charging system suction valves, and auxiliary feedwater control valves as identified in Amendment 14 to the FSAR. Plant installation drawings were reviewed and it appeared that these areas were overlooked. For this reason, the applicant was required to completly review smoke detector installations and to notify the staff that all areas requiring detection have been identified and that detectors have been installed. By letter dated March 5, 1987, the applicant stated that smoke detector installations had been reviewed. As a result of this review, eight areas were identified in which detection should have been installed but had not been and four areas were identified in which there were no plans to install detectors. The applicant indicated that the eight areas will be provided with the required fire detection. In an FSAR revision, the applicant identified the four areas (Fire Areas PA-3, PT-1, SG-1N and SG-15) as a deviation from Section C.6a(1) BTP CMEB 9.5-1 because general area detection has not been provided. However, the applicant stated that all areas containing combustible materials or that represent a potential exposure to safety-related equipment are provided with detection. On the basis of this information, the deviation from lack of general area detection for the four areas identified is acceptable.

As a result of a meeting at the site on December 5, 1984 between the staff and the applicant, the staff expressed an additional fire protection concern. This concern addressed the electrical supervision of fire protection equipment. In the SER, the staff indicated that the fire alarm system complies with NFPA 72D for a class "A" system. During the December 5, 1984 visit, the staff expressed concerns about the fire alarm system's compliance with NFPA 72D regarding circuit supervision. In the trip report dated January 30, 1985, the staff requested that the applicant provide verification that the fire alarm system complies with NFPA 72D as a Class A system. A response to concerns identified in the trip report was provided to the staff on May 24, 1985 by the applicant. The applicant stated that the early warning fire detection system

is Class A per NFPA 72D. The applicant also stated that the circuits between detectors and the CO_2 panels are Class A. On the basis of this information, the staff concluded in SSER 3 that all circuits of the fire detection system are Class A. However, during the site audit of January 27-30, 1987, additional concerns were raised about the fire alarm system and its compliance with NFPA 72D per Section C.6 of BTP CMEB 9.5-1. Specifically, certain fire alarm system circuits appeared not to be supervised per NFPA 72D. The staff is concerned that a single break or ground fault condition could render portions of the fire alarm system inoperable (including control room annunicator circuits and sprinkler system circuits). The operating license would be conditioned to direct the licensee to develop and implement a test procedure to confirm the operability of these circuits once every 31 days.

Fire Protection Water Supply System

During the site audit, the applicant stated that fire hydrant 16, located at the southwest corner of the turbine building, was relocated because it interfered with the installation of the auxiliary boiler and the security perimeter fence, thus providing a 370-foot spacing indicated in Section C.6.b(7) of BTP CMEB 9.5-1. The area was observed during the audit and coverage for nearby hazards appeared adequate. Therefore, the spacing between hydrants 15 and 16 is an acceptable deviation from the SRP.

9.5.1.6 Fire Protection of Specific Plant Areas

Control Room

In Amendment 14 to the FSAR, the applicant identified the following deviations from Section C.7.b of BTP CMEB 9.5-1: (1) 1-hour separation was not provided between the control room and the shift supervisor's office, (2) aluminum conduit rather than steel was run under the raised floor, and (3) carpeting may be provided.

During the site audit, the shift supervisor's office was observed to be a small area in the back of the control room, that had been created by installing partial-height unrated walls. The ceiling of the office was observed to be of solid drop-type construction, which would preclude any smoke from reaching the detectors at the ceiling. The addition of a 1-hour rated barrier would not significantly increase the level of fire safety; however, the applicant should either install detection in the office area or replace the ceiling with open lattice-type panels. By letter dated March 5, 1987, in order to resolve this concern, the applicant committed to install a smoke detector in the shift supervisor's office. The staff finds this acceptable.

The use of aluminum conduit in a raised-floor area is limited to a 3- to 4-foot-wide section between the bench board and the vertical boards. Smoke detection is provided in the boards and no combustible material, except conduit, is located in the raised-floor area. Replacing the aluminum conduit with steel would not significantly increase the level of fire protection, and the aluminum conduit is, therefore, acceptable.

Although carpeting has not yet been installed in the control room, the applicant may install it in the future. The applicant stated that if carpeting is installed, it will have a flame-spread rating of less than 50 per ASTM E-84 tunnel

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test and a critical radiant flux that exceeds the minimum of 0.45 watts per square centimeter used to define Class 1 interior finishes. The control room is continuously manned and extinguishers are provided in the immediate areas. Thus, the addition of carpeting of this type in the control room would not significantly reduce the level of fire safety, and is acceptable.

Cable Spreading Room

In the SER, the staff raised concerns regarding the use of automatic CO_2 in the cable spreading room. As a result, the applicant made certain modifications to ensure that fire brigade members could adequately access all areas of the room. In SSER 3, the staff indicated that this issue would remain as backfit issue 7 pending a site visit which would verify that (1) the applicant had implemented the recommendations provided by a human factors expert in a letter dated March 18, 1985, (2) the temporary ramps and platforms needed to facilitate passages had been replaced with permanent versions, and (3) training was provided to the fire brigade. The staff identified a fourth item, the reach of hose streams to the northwest corner, as a deviation and requested the applicant to justify their design. In Amendment 14 to the FSAR, the applicant identified the cable spreading room as a deviation and provided a detailed discussion of the room's fire protection features. During the site audit, the room was reviewed against Items 1, 2, and 3 of SSER 3. The staff noted that issues identified by the human factors expert have been corrected, permanent ramps have been installed to ease accessibility to certain areas, and training procedures were reviewed to ensure that the cable spreading room is specifically addressed. Thus, the issues identified in previous evaluations have been adequately addressed by the applicant, and backfit issue 7 is considered closed. The applicant's deviation request in Amendment 14 to the FSAR was also reviewed and found to adequately resolve previous concerns. Therefore, the existing fire protection for the cable spreading room is an acceptable deviation from Section C.7.c of BTP CMEB 9.5-1.

Safety-Related Pumps

Section C.7.k of BTP CMEB 9.5-1 states that redundant safety-related pumps should be separated from each other by a 3-hour fire barrier. In Amendment 14 to the FSAR, the applicant stated that the fuel-pool cooling pumps are not separated by a 3-hour barrier. The pumps are located in the fuel building in a fire area with minimal combustibles. Smoke detectors are provided over the pumps, and hose racks are in the immediate area. The fuel-pool cooling pumps are not required for safe shutdown, and loss of the pumps would not affect plant safety. Therefore, the lack of 3-hour separation between the redundant fuel-pool cooling pumps is an acceptable deviation from BTP CMEB 9.5-1, Section C.7.k.

New Fuel Area and Spent Fuel Pool Area

Sections C.7.k and C.7.m of BTP CMEB 9.5-1 state that detection should be provided for the new fuel and spent fuel pool areas. The applicant stated in Amendment 14 to the FSAR that detection is not provided for these areas. Combustible loading in these areas is negligible and detection is provided for the fuel-pool cooling pumps. During the site audit of January 27-30, 1987, this area was observed and it was determined that because of limited floor space and controlled personnel access an accumulation of transient combustibles is

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unlikely. However, the new fuel storage room was observed to have some transient combustibles. By letter dated February 11, 1987, the applicant committed to provide administrative controls on access to this area in order to limit storage of transient combustibles. Therefore, the addition of detection in the new and spent-fuel pool areas would not significantly enhance fire safety. With the addition of administrative controls to control combustibles in the new fuel storage room, the lack of detection in the new and spent-fuel areas is an acceptable deviation from Section C.7.m of BTP CMEB 9.5-1.

Radwaste and Decontamination Area

The applicant stated in Amendment 14 to the FSAR that the radwaste and decontamination areas deviate from C.7.n of BTP CMEB 9.5-1 because they are not provided with detection and suppression throughout. These areas include the waste handling building (WH-1), condensate polishing building (CP-1), and the decontamination building (FP-1). The majority of these areas are essentially free of combustibles; however, the applicant has provided automatic suppression where there is a possibility of the accumulation of transient combustibles. These areas include the resin storage area, the primary chemistry lab, and the radwaste baler area. A suppression system is also provided for the charcoal filter unit in the decontamination building. Hose racks are provided throughout the area. No equipment or circuitry required for safe shutdown is located in these areas. The addition of general area detection and suppression would not significantly increase the level of plant fire safety. Therefore, the lack of area detection and suppression for the radwaste and decontamination areas is an acceptable deviation from C.7.m of BTP CMEB 9.5-1.

General Areas

In Generic Letter (GL) 86-10, the staff affirmed that the NFPA codes identified in the Branch Technical Position should be followed in the design and installation of fire protection systems and plant features. Where deviations from these codes exist, utilities should identify these conditions to the staff and provide justification. The applicant has identified certain deviations. These conditions have been evaluated in the SER and its supplements. No other deviations have been identified by the applicant or approved by the staff.

The applicant has also proposed to delete certain fire-protection related Technical Specifications in accordance with the guidance issued in GL 86-10. Originally, the proposal was not acceptable because certain surveillance requirements from the Technical Specifications were not included in the applicant's site administrative procedures. However, the applicant subsequently committed to revise these site procedures to include the missing surveillance requirements. On this basis, the staff considers this issue closed.

9.5.1.7 Summary of Approved Deviations From BTP CMEB 9.5-1

The SER through Supplement 3 provides details on eight deviations from BTP CMEB 9.5-1. On the basis of the evaluations in this supplement (SSER 5), the staff concludes that the above deviations are acceptable. The evaluation closes confirmatory issue 48(c).

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.1 Emergency Diesel Engine Auxiliary Support Systems (General)

In the SER, the staff stated that the applicant committed to develop its own diesel generator training program that will be based on information obtained while the vendor was training the applicant's personnel. The staff found the commitment acceptable subject to confirmation that the applicant's ongoing training program will be in place before fuel loading.

By a letter dated April 13, 1987, the applicant stated that this issue is met by training class No. 6035, "BV-2 Diesel Generator Training." This is responsive to the staff's concern. Therefore, confirmatory issue 37 is considered resolved.

Confirmatory issue 38 concerns vibration of equipment relocated from the engine skid to a free-standing panel or a wall-mounted seismically qualified configuration. The staff stated that NRC Region I will follow this issue. Region I will address this issue in Inspection Report 50-412/87-35. On this basis, confirmatory issue 38 is closed.

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10 STEAM AND POWER CONVERSION SYSTEM

10.2 Turbine Generator

In the SER, the staff identified items to be resolved as part of the Technical Specifications review to justify a monthly valve test interval for turbine generator valves (turbine stop, control intercept, and reheat stop valves).

In a letter dated May 26, 1987, the applicant requested that the surveillance requirement in the Technical Specifications for turbine overspeed for Beaver Valley Unit 2 specify a turbine valve testing frequency of at least once in 31 days.

The staff's position stated in Standard Review Plan Section 10.2, "Steam Turbines" (NUREG-0800), which requires weekly testing of turbine valves was established after extensive discussions with major steam turbine manufacturers, and is based largely on engineering judgment and the recommendations of these manufacturers.

Westinghouse, in meetings with the staff on March 23 and August 16, 1983, presented results of a generic study on the generation of turbine missiles on nuclear turbines conducted on behalf of some licensees and applicants. This study specifically includes consideration of the testing requirements for the turbine overspeed protection valves on turbines with steam chest valve arrangement of the type installed at the Beaver Valley Station, Unit No. 2. Westinghouse stated that the results of this study show that on such machines, turbine valve operability and reliability will not be significantly affected by increasing the periodic valve testing from weekly to a much longer interval. Westinghouse also concluded that reduced turbine valve testing on this type of turbine has little or no effect on the probability of generating turbine missiles. In Westinghouse's judgment, lack of a significant number of valve failures, good operating experience, and a well-planned turbine valve maintenance and inspection program provide reasonable bases to allow a monthly periodic test interval for turbines with valve arrangements similar to those installed at Beaver Valley. Since the above meetings, Westinghouse has issued a formal recommendation to its customers who have turbines employing turbine valves and steam chest arrangements of the type installed at Beaver Valley Unit 2 to establish monthly valve testing.

The staff has evaluated the information submitted by the applicant in the FSAR and in the May 26, 1987 letter, and Westinghouse information presented at the March 23 and August 16, 1983 meetings. Considering the information presented by the applicant and Westinghouse, and the staff's original basis for the Standard Technical Specifications, the staff concludes that the surveillance interval between periodic turbine valve testing can be established for Beaver Valley Unit 2 to be at least once in 31 days without significantly affecting the capability of the turbine valves to function on demand.

In summary, the bases for considering relief from the Standard Technical Specifications at Beaver Valley Unit 2 were:

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(1) Up to now, the test frequency of nuclear service turbine valves has been largely based on experience with turbine generators installed in fossil plants. The requirement to test and inspect nuclear turbine valves on a weekly basis was originally included in the Standard Technical Specifications on the basis of experience and to ensure functional operability on demand to avert a potential turbine overspeed condition that could result in the generation of turbine missiles. The objective of the valve testing was to ensure high valve operability and reliability in order to minimize the probability of generating destructive missiles that could damage safety-related equipment and thereby prevent safe shutdown of the plant. The turbine control and overspeed protection system is designed to control turbine action under all normal and abnormal conditions to ensure that a turbine trip from full load will not cause the turbine to overspeed beyond acceptable limits, thus minimizing the probability of generating turbine missiles. Although the turbine control and overspeed protection system is not relied on to perform a safety function, it controls a plant process that has potential to affect plant safety.

(2) Nuclear turbine valves have proven to be extremely reliable in service as evidenced by the lack of failures over the many years of nuclear plant operation. This proven reliability can also be attributed to the all-volatile chemical treatment of feedwater that minimizes steam generator carryover and essentially eliminates valve failure due to scale buildup on the valve moving parts.

(3) There is no satisfactory statistical basis to determine frequency of turbine valve testing. Up to now, test frequency of these valves has been largely based on experience with turbine generators installed in fossil plants. The results of the Westinghouse generic turbine missile study show that reduced turbine valve testing frequency on nuclear turbines of the type installed at Beaver Valley Unit 2 has minimal effect on valve operability, reliability, and probability of turbine missile generation.

(4) The applicant's ongoing maintenance, inspection, and turbine valve test program described in the FSAR, coupled with installed turbine generator, protective features, an inplace inspection program of the low-pressure turbine discs, and the proposed Technical Specifications surveillance requirement which is consistent with the Westinghouse recommendations, provides reasonable assurance of a low probability of missile generation due to design overspeed. This program performed on a periodic basis coupled with monthly testing of all turbine valves is satisfactory to the staff.

(5) The data and rationale presented by Westinghouse at the March and August 1983 and at other previous meetings with the staff and the staff's understanding of the data presented to date.

(6) Testing of turbine control valves on Westinghouse base-loaded machines with steam chest arrangements necessitates reducing generator output for a period of several hours. The sequence of testing valves during turbine operation requires placing the turbine on manual control and repositioning all turbine control valves on a base-loaded machine results in reduced steam flow to the turbine with a consequent reduction in generator output of about 5%. All turbine control valves are tested in a relatively short

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time (about 35 to 40 minutes). The bulk of the time (approximately 2-1/2 to 3 hours) is consumed in slowly lowering reactor output to correspond with the reduced turbine generator output to permit control valve testing. On completion of valve tests, a similar time period is consumed in slowly increasing reactor power to permit full load operation of the turbine generator. The lowering and increasing of reactor output must be accomplished slowly to minimize xenon spiking. The potential for xenon spiking exists when subjecting the nuclear steam supply system to cyclical power transients, and this was factored in the staff's consideration.

(7) The staff understands from the above discussion and applicant-supplied information that the Beaver Valley Unit 2 valve casing arrangement is similar to the arrangement at other plants with approved monthly test intervals and that analysis results provided in the FSAR were calculated with methodology and data basis similar to that for the other approved plants.

On these bases, the staff concludes that establishing the turbine valve testing interval at Beaver Valley Unit 2 to be at least once per 31 days is acceptable.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.1 Management and Technical Support Organization

Beaver Valley Power Station (BVPS) Units 1 and 2 are owned by a consortium of electric utilities. Duquesne Light Company (DLC) was designated by the consortium as the agent for the design, construction, and operation of the BVPS units. This review addresses only the organization and management of DLC, the company considered to be the applicant for the operating license.

A simplified chart of the DLC corporate organization is included as Figure 13.1. The Senior Vice President (SVP) of the Nuclear Group, reporting directly to the President of DLC, has primary responsibility for completing construction, for testing and startup, and ultimately for the safe and efficient operation of BVPS Unit 2. The applicant proposes that the incumbent have a Bachelor of Science degree in engineering or a physical science and at least ten years of experience in design, operation, maintenance, testing, or licensing of nuclear power plants, at least five years of which shall have been in a position of line responsibility.

The two major organizational units reporting to the Senior Vice President of the Nuclear Group (see Figure 13.2) are the Vice President Nuclear, providing engineering and construction services, among other things, and the Senior Manager, Nuclear Operations, responsible for operation of the two BVPS units.

Also reporting to the SVP of the Nuclear Group are the Startup Manager; the Manager, Quality Assurance; the Manager, Budget and Fuel Contracts; the BVPS Unit 2 Project Organization (BV-2 Project); and the Offsite Review Committee (ORC).

Technical assistance can be obtained from other qualified corporate or consultant organizations. However, full responsibility for BVPS Unit 2 (BVPS-2) resides within the Nuclear Group.

The organizational structure of Duquesne Light Company is evolving as construction of the second, and final, Beaver Valley nuclear unit nears completion. In 1982, DLC established a Nuclear Construction Division with overall responsibility for BVPS-2. More recently, as reflected in the current organization chart, the SVP of the Nuclear Group was assigned responsibility for the project to ensure the orderly transition from construction to operation. Upon completion of construction, the BVPS-2 Project Organization, now reporting directly to the SVP of the Nuclear Group, will be eliminated, and project personnel will be reassigned within the Nuclear Group Organization.

13.1.1.1 Vice President, Nuclear

The applicant refers to this segment of the organization as the Nuclear Services Unit. The Nuclear Services Unit provides technical support to the operation of

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the two nuclear units. The six organizational subunits reporting to the Vice President (VP), Nuclear are the General Manager, Nuclear Engineering and Records; Manager, Nuclear Construction; Manager, Nuclear Training; Manager, Nuclear Safety; Manager, Administrative Services; and SAPS (Shippingport Atomic Power Station) Decommissioning Representative. The Independent Safety Evaluation Group (ISEG) reports to the Manager of Nuclear Safety. (See Section 13.4.1.2 for discussion of the ORC and the ISEG.)

The applicant proposes that the VP, Nuclear shall have a Bachelor of Science degree in engineering or a related science. He shall also have ten or more years of responsible power plant experience. A minimum of four of these years shall have been supervisory or management experience and a minimum of three of these years shall have been in administration or operation of a nuclear generating station.

Nuclear Engineering and Records Unit

The Nuclear Engineering and Records Unit (NERU) headed by the General Manager, NERU provides engineering and design requirements, engineering information to support plant operation and maintenance, and maintains and controls both engineering and operations records. Technical capabilities provided by NERU in support of plant operations include nuclear, mechanical, structural, electrical, thermal-hydraulic, metallurgical and materials, and instrumentation and controls engineering.

The applicant proposes that the General Manager, NERU, have a Bachelor of Science degree in engineering from an accredited college or university, shall be a registered professional engineer in the Commonwealth of Pennsylvania, and shall have ten years of responsible engineering experience in electric utility work with at least eight years of that in the nuclear power field.

Nuclear Construction Department

Nuclear Construction Department (NCD) activities involve installation or modification of station equipment as required. The NCD is headed by the Manager, Nuclear Construction. Both the NERU and the NCD can obtain technical assistance from other corporate or consultant organizations that have been qualified by both the NERU and Quality Assurance Department to provide the required services.

The applicant has not proposed any minimum qualifications for the Manager, Nuclear Construction. The applicant should establish standards for this position.

Nuclear Training Department

The Nuclear Training Department is headed by the Manager, Nuclear Training and provides various first aid, fire safety, and technical training courses to personnel who monitor radiation, operators, engineers, and administrators.

The applicant proposes that the Manager, Nuclear Training have a Bachelor of Science degree in a science or appropriate experience in the nuclear training field, hold and maintain an NRC Senior Reactor Operator license, and have four or more years of experience in power generating stations.

Administrative Services Department

The Administrative Services Department, headed by the Manager, Administrative Services, is responsible for handling relations between DLC and Nuclear Group employees, including recruitment of new employees, promotion, demotion, reassignment, testing and transfer of existing employees, administration of the labor contract, handling of personnel problems, processing of job bids, evaluation of employee qualifications, supervision, and coordination of grievance procedures. The department provides clerical support for the Nuclear Group. The department is also responsible for the Physical Security Plan and the contract guard force.

The applicant proposes that the Manager, Administrative Services have a bachelor's degree or its equivalent with emphasis on personnel administration and have ten or more years of experience in a generating station where he/she was responsible for operation, maintenance, technical, or administrative work.

Nuclear Safety Department

The Nuclear Safety Department, headed by the Manager, Nuclear Safety, is responsible for licensing activities, the ISEG, and administration of the Station Fire Protection Program. The Licensing Section is the intermediary between the applicant and NRC in routine matters relating to licenses; amendment; exemptions; licensing documents; I&E bulletins, circulars, and information notices; and inspections.

The applicant proposes that the Manager, Nuclear Safety, have a Bachelor of Science degree in engineering or hold an NRC Senior Reactor Operator license. The incumbent shall also have at least ten years of experience in design, engineering, operation, maintenance, or testing of power plants, of which five years shall be nuclear experience.

Shippingport Atomic Power Station Decommissioning Project

This organization unit is only involved in decommissioning the Shippingport Atomic Power Station.

13.1.1.2 Manager, Quality Assurance

The Quality Assurance Unit provides for administration and auditing of the quality assurance program during both the construction and operation phases. In addition the Quality Assurance Unit implements the quality control program, the preservice and inservice inspection programs, and the vendor surveillance program for BVPS-1 and BVPS-2.

The applicant proposes that the Manager, Quality Assurance have a Bachelor of Science degree in engineering or physical science from an accredited college or university or 20 years of experience in the design, construction, or operation of generating facilities. The Manager shall also have at least ten years of experience in nuclear plant engineering, construction, operations, or quality assurance/quality control.

The applicant has not committed to meet the personnel qualification requirements of ANSI N18.1-1971. The staff's review of the qualification requirements

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for key management positions supporting the operation of BVPS-2 finds that positions are to be filled with technically qualified individuals. The staff also notes that through the long-term involvement of the applicant in commercial nuclear power, there are numerous individuals at the corporate level with extensive experience in nuclear power plant operations.

13.1.1.3 Summary and Conclusions

The applicant has described its organization for the management of, and its means for providing, technical support for the plant staff during operation of the facility. The applicant's organization has the station and the offsite support activities directly under the SVP, Nuclear Group.

On the basis of the above discussion, the part of the open issue 6 which covers Section 13.1.2 is closed.

13.1.2 Operating Organization, Nuclear Operations Unit

Operation of the two Beaver Valley units is under the Senior Manager, Nuclear Operations, who reports to the Senior Vice President, Nuclear Group (see Figure 13.2). Reporting to the Senior Manager are the Manager, Planning and Outage Management; the Manager, Technical Services; the Manager, Radiological Control; and the Plant Manager.

13.1.2.1 Planning and Outage Management Organization

The Planning and Outage Management Organization is responsible for planning and scheduling outage and non-outage modifications of the nuclear units, including refueling and other outage operations. This organization is also responsible for tracking and analyzing trends in maintenance actions. Responsibilities regarding refueling include review and approval of refueling plans and procedures, examination of refueling results and records, and preparation of post-refueling reports.

13.1.2.2 Technical Services Organization

The Technical Services Organization, headed by the Manager, Technical Services, consists of the Onsite Safety Committee (OSC) and Technical Advisory Engineering, Chemistry, and Material Management Sections.

The OSC under the Director of Plant Safety Review, is responsible for reviewing those items designated in the administrative controls section of the Technical Specifications, for providing review material for the ORC, and for advising the Plant Manager on all matters related to nuclear safety.

The Technical Advisory Engineering Section provides the Shift Technical Advisor (STA) on each operating shift. The STAs are responsible for advising the operating shift operations supervisor about the assessment of transient and accident situations and for performing incident investigations. The STAs also review related industry operating experience for applicability, and initiate safety measures as appropriate.

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The Chemistry Section is responsible for station chemistry and radiochemistry activities, including preparation, implementation, and interpretation of procedures and results, and for maintenance of analytical equipment and analytical records. The section is also responsible for preparing reports to the Environmental Protection Agency and to the Pennsylvania Department of Environmental Conservation.

The Material Management Section is responsible for the program for procurement, handling, and maintenance of material associated with safety-related applications.

13.1.2.3 Radiological Control Department

Radiological controls and industrial safety activities are directed by the Manager, Radiological Control.

13.1.2.4 Plant Operating Organization

The Plant Manager, as the head of the Plant Operating Organization, has authority over operations, maintenance, instrumentation and control, and testing activities. The Plant Operating Organization is depicted in Figure 13.3.

Operations Department

The Assistant Plant Manager directs the Operations Department; this department has the principal responsibility of the physical operation of the two nuclear units. Responsibilities also include surveillance activities for Technical Specifications and inservice inspection testing compliance, solid waste preparation, maintenance of fire brigade complement, and balance-of-plant performance monitoring. During extended plant outages, the Assistant Plant Manager may be directed to assume Plant Manager duties.

The applicant has established that the Plant Manager must hold a Bachelor of Science degree in engineering or its equivalent, must have six years of responsible power plant experience, of which at least three are nuclear plant experience, and must hold an NRC Senior Reactor Operator's license.

Under the Assistant Plant Manager is a Nuclear Operating Supervisor for each of the two BVPS units and a Nuclear Operating Supervisor, Operations Support. The Nuclear Operating Supervisor for each unit is responsible for the coordination of the operating activities associated with the assigned unit, including the operation of the equipment, buildings, and grounds associated with that unit. The Nuclear Operating Supervisor will be required to hold a Bachelor of Science degree in engineering or its equivalent, have six or more years of responsible power plant experience, at least three of which are nuclear experience, and must hold an NRC Senior Reactor Operator's license.

The Nuclear Operating Supervisor, Operations Support is responsible for developing overall station operating policy and procedures and coordinating and supervising offsite operating groups' activities to ensure the proper disposition of operations problems and station responsibilities. This position requires a high school diploma, five years of experience in technical or responsible operation positions in a generating station, at least three of which have been at the BVPS, and an NRC Senior Reactor Operator's license at BVPS.

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The minimum shift crew composition for various modes of operation for BVPS Units 1 and 2 is shown in Table 13.1. In the Operational Readiness Review meeting of May 18, 1987, the applicant informed the staff that senior reactor operators will have an average of 5 years of licensed nuclear experience, and reactor operators will have an average of 3 years of nuclear experience. The staff noted that the Nuclear Shift Supervisor, the Nuclear Assistant Shift Operating Foreman, the Nuclear Control Operators, and the Nuclear Operators are assigned from the Operations Department; the STA and the Chemist or Chemical Analyst are assigned to the "common facility" from the Technical Services Organization; and the two Radiation Technicians are assigned from the Radiological Controls Department.

The STA, the Chemist, and the Radiation Technicians are responsible for both Unit 1 and Unit 2.

Maintenance Department

Mechanical and electrical maintenance activities are accomplished under the site Maintenance Director. These include: preventive, predictive, and corrective maintenance programs; all mechanical and electrical surveillance and testing related to technical specification and inservice testing compliance; and the plant lubrication program for all installed equipment and all equipment related to the Equipment Qualification Program.

The Maintenance Department provides support during the initial startup test program. The department is responsible for all subsequent assembly and disassembly of major physical plant components including the reactor vessel.

Instrument and Control Department

Maintenance of monitoring instruments and controls is the responsibility of the site Instrument and Control Director. The department provides support during startup testing and is responsible for all subsequent testing and maintenance of instrumentation systems, including reactor vessel instrumentation during outages.

Computer maintenance is included within the responsibilities of this department.

Testing and Plant Performance Department

Responsibilities of the Testing and Plant Performance Director include: containment structural and integrated leak rate testing, all reactor engineering, initial startup and refueling startup, low-power physics testing, major nuclear fluid system testing, ventilation systems, filter systems, and fire protection damper and fire stop adequacy. Department staff is responsible for the balance-of-plant performance, heat exchanger monitoring, and pump/motor vibration monitoring to provide data for plant reliability and maintainability programs used in the assessment of the capability of plant equipment.

13.1.2.5 Summary and Conclusions

The applicant has complied with the guidelines of SRP Section 13.1.2. On the basis of the above review, the part of open issue 6 that covers Section 13.1.2 is closed.

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13.3 Emergency Planning

13.3.1 Introduction

The staff reviewed Issue 8, Revision 0 of the Beaver Valley emergency plan as reported in the SER. Additional information was required from the applicant for two open items (as described below), identified in the plan. The applicant responded with Issue 8, Revision 1 of the plan, submitted by letter dated August 19, 1986, and provided additional information during the onsite inspection of March 2-6, 1987. The applicant published Issue 8, Revision 0 of the implementing procedures and Issue 9, Revision 0 of the plan on March 26, 1987.

The staff has reviewed the latest revisions of the plan and procedures against the requirements and guidance criteria identified in 10 CFR 50.47(b), Appendix E to 10 CFR 50, and NUREG-0654/FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Remergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated November 1980. In addition, the staff has evaluated the emergency preparedness exercise conducted on November 19, 1986.

13.3.2 Evaluation of the Applicant's Onsite Emergency Plan

This evaluation addresses those items in the SER that required resolution. The following discussion through Section 13.3.5.2 closes open issue 8.

13.3.2.4 Emergency Classification System

The item requiring resolution in this section concerned certain initiating conditions as described in Appendix A to NUREG-0654 that were not addressed or were deficient in the emergency plan. These deficiencies were partially corrected in Issue 8, Revision 1 of the emergency plan. Following discussions with the applicant, a modified plan (Issue 9, Revision 0) was submitted to correct the deficient initiating conditions and to address the missing initiating conditions. The staff has reviewed these submittals and now finds that the applicant's emergency classification system and emergency action level scheme conform to the guidance in NUREG-0654 and are acceptable.

13.3.2.12 Medical and Public Health Support

The item requiring resolution in this section concerned the annual certification that the letters of agreement are current. The applicant has included a statement in Issue 8, Revision 1 of the emergency plan that commits to an annual review and certification that the letters of agreement are current. On the basis of the applicant's commitment in the revised plan, the staff finds that this portion of the emergency plan is satisfactory.

13.3.3 Result of Emergency Preparedness Exercise

The latest full-participation emergency preparedness exercise at Beaver Valley was conducted on November 19, 1986. The NRC review of the onsite portion of the exercise, published in Inspection Report 50-334/86-27, identified no deficiencies. A number of areas were identified for corrective action and will be the subject of followup inspections on a schedule determined by the NRC Region I

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office. Although there were areas requiring corrective action, the staff concludes that the applicant adequately demonstrated measures to protect the health and safety of the public.

13.3.4 Conclusion on Onsite Emergency Preparedness

The staff concludes that onsite emergency preparedness meets the requirements of 10 CFR 50 and Appendix E thereto for issuance of a license authorizing fuel loading and low-power operation.

13.3.5 Review of Offsite Emergency Preparedness

13.3.5.1 FEMA Report on Offsite Preparedness

The Federal Emergency Management Agency (FEMA) is currently reviewing the emergency plans of the States of West Virginia and Ohio, and the Commonwealth of Pennsylvania, as well as the local government plans of Beaver County, Pennsylvania; Columbiana County, Ohio; and Hancock County, West Virginia, in support of the Beaver Valley Power Station and will issue a report on its review of the plans and on the results of the exercise conducted on November 19, 1986, at Beaver Valley. The staff will review FEMA's findings and will then issue a final determination on the state of onsite and offsite emergency preparedness.

13.3.5.2 Offsite Emergency Planning Medical Services

In a decision, GUARD v. NRC, 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR 50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the public off site exposed to dangerous levels of radiation. Subsequently, the Commission issued interim guidance on May 21, 1985, requiring applicants for nuclear power reactor operating licenses to provide confirmation that each emergency plan contains a list of local or regional medical treatment facilities and to commit to comply with any additional requirements imposed by the Commission in response to the GUARD remand.

On September 17, 1986, the Commission issued its final policy and interim guidance to be followed in determining compliance with this regulation. The Commission directed that licensing boards (and in uncontested cases, the staff) should rely on the interim guidance of the May 21, 1985 Statement of Policy until the NRC staff develops, (in consultation with FEMA) and issues appropriate detailed guidance, and until the licensees, applicants, and State and local governments have had time to implement the detailed guidance. Specifically, the applicant is required to satisfy the requirements of planning standard 10 CFR 50.47(b)(12) as interpreted by the Commission prior to the GUARD decision and shall commit itself to full compliance with the requirements imposed by the Commission in the September 17, 1986 policy statement. Consistent with the foregoing Statement of Policy, both onsite and offsite emergency plans contain lists of medical treatment facilities, and by letter dated April 2, 1987, the applicant committed to full compliance with the Commission's September 17, 1986 policy statement.

13.4 Operational Review

The applicant has established a review and audit program to ensure that operations of the two BVPS units are accomplished in a safe manner consistent with

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license provisions, approved procedures, and company policy. Review also verifies that unusual events are promptly investigated and corrected, and detects trends or conditions that may not be apparent to a day-to-day observer.

Three groups have been established to perform reviews: the Onsite Safety Committee (OSC), the Offsite Review Committee (ORC), and the Independent Safety Evaluation Group (ISEG). The ISEG is located on site but reports to the Manager, Nuclear Safety in the Nuclear Services Unit.

The audit program is the responsibility of the Operations Quality Assurance Department. Further discussion of quality assurance activities is found in Section 17. Certain facility activities will be subject to audit by the ORC.

13.4.1 Review

13.4.1.1 Onsite Review

The Onsite Safety Committee (OSC), which reports to the Plant Manager, is responsible for the following reviews and investigations:

(1) Review procedures (and changes thereto) that affect nuclear safety.

(2) Review proposed tests and experiments that affect nuclear safety.

(3) Review proposed changes to the Technical Specifications.

(4) Review proposed changes to plant systems or equipment that affect nuclear safety.

(5) Investigate violations of the Technical Specifications and make recommendations to prevent recurrence.

(6) Review events reportable to the NRC under 10 CFR 50.72.

(7) Review facility operations to detect potential safety hazards.

(8) Perform special reviews, investigations, or analyses upon request of the Chairman of the ORC.

(9) Review the Security Plan and implementing procedures.

(10) Review the Emergency Plan and implementing procedures.

The OSC, which will meet at least monthly, will consist of members of the station staff who will be appointed by the Chairman of the OSC to serve for at least a six-month period. The Director of Safety Review will be the Chairman of the OSC. Members will represent a range of technical specialities and will meet the minimum qualifications of ANSI N18.1-1971 Section 4.4 for comparable positions.

13.4.1.2 Independent Review

The Offsite Review Committee (ORC) will perform an independent review of all matters that involve safety considerations relating to operation of the station.

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The primary purpose of the ORC is to ensure that station operation is consistent with the terms of the NRC operating license and with applicable health and safety regulations. Specifically, the following items will be reviewed by the ORC:

(1) safety evaluations for changes to procedures, equipment, or systems

(2) tests or experiments completed under the provision of 10 CFR 50.59

(3) proposed changes to the Technical Specifications or operating license

(4) violations of regulations, codes, orders, Technical Specifications, license requirements, and internal procedures or instructions having nuclear safety significance

(5) operating abnormalities and significant deviations from expected per formance of plant equipment which affect nuclear safety

(6) occurrences reportable to the NRC under 10 CFR 50.72

(7) indications of deficiencies in design or operation of safety-related structures, systems, or components

(8) reports and meeting minutes of the OSC

The members of the ORC are in management positions independent of the Plant Manager. The positions represented are specified in the BVPS-2 Technical Specifications. The Westinghouse Electric Corporation Site Service Manager will be a member of the ORC and an outside consultant for chemistry and radiochemistry will be included. Each member of the ORC will have a Bachelor of Science degree in engineering or a related science, five years of experience in this specialty field, and will possess qualifications commensurate with the position to which he or she is assigned in the applicant's organization. The applicant anticipates that personnel assigned to the ORC collectively will have experience and competence to meet the intent of Section 4.3.1 of ANSI N18.7, as endorsed by Regulatory Guide 1.33.

The ORC will meet quarterly during the first year of Unit 2 operation and at least once in every six-month period thereafter. ORC findings and minutes of ORC meetings will be distributed to ORC members, management personnel, the Manager of Nuclear Safety; the VP, Nuclear; and the SVP, Nuclear Group.

13.4.1.3 Independent Safety Evaluation Group

Independent reviews of safety-related activities will also be performed by the Independent Safety Evaluation Group (ISEG). The objective of the ISEG review is to make recommendations to management on the means to improve the overall quality and safety of nuclear operations. The full-time ISEG staff of at least five individuals will be located at the site and will report to the Manager, Nuclear Safety.

The ISEG supervisor shall have either a Bachelor of Science degree in engineering or a related science, an advanced degree in engineering or a related science, or the equivalent, and shall have ten years of experience in the operation, design, technical support, or licensing of a nuclear facility. The rest of the staff shall have at least bachelor's degrees and two years of relevant experience.

The ISEG will have no approval or signoff responsibility for any subjects reviewed. The group will examine industry activities and operating experience information for the improvement of plant safety. The ISEG will also independently review BVPS activities, programs, procedures, modifications, and operational problems, and will maintain surveillance of plant operations to advise management on overall quality and safety of the station.

13.4.2 Audit

A system of audits has been established to verify and document compliance with regulatory requirements, including license provisions, operating procedures, and operations quality assurance administrative controls. The Quality Assurance Unit is responsible for auditing the applicant's organization as well as for auditing participating vendors and contractors to ensure that the requirements of the Operations QA Program are met. The ORC will conduct limited audits of specified technical activities at the station.

On the basis of the above review, the part of open issue 6 which covers Section 13.4 is closed.

13.5 Station Administrative Procedures

13.5.1 Administrative Procedures

The applicant points out in the FSAR that it has developed administrative procedures to support BVPS-1 operation and that these procedures will be revised as required to support BVPS-2 operation. FSAR Table 13.5-1, provides the "Scope of the BVPS-2 Station Administrative Procedures." Procedures for fire protection and for crane operation are not specifically identified in the scope. The text of the FSAR, however, identifies the qualification standard to be applied to certain crane operators.

Review of administrative procedures has been performed by Region I staff as follows:

Shift Staff Responsibilities

The applicant has stated that procedures will include requirements set forth in 10 CFR 50.54, Paragraphs (i), (j), (k), (l), and (m) and will meet the intent of NUREG-0694, Item I.C.3 for shift supervisor responsibilities. Staff review is documented in Inspection Report 50-412/87-02. This issue is closed.

Shift Relief and Turnover

The applicant stated that the procedures will meet the intent of NUREG-0694, Item I.C.2 for shift relief and turnover for shift operating personnel. Staff review is documented in Inspection Report 50-412/87-02. This issue is closed.

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Control Room Access

The applicant stated that the procedures will meet the intent of NUREG-0694, Item I.C.4 for control room access. Staff review is documented in Inspection Report 50-412/87-02. This issue is closed.

Limitations on Working Hours

The applicant has indicated that procedures will meet the intent of NUREG-0737, Item I.A.1.3 as modified by Generic Letter 82-12 for limits on working hours. Staff review is documented in Inspection Report 50-412/87-02. This issue is closed.

Feedback of Operating Experience

The applicant has indicated that procedures will meet the intent of NUREG-0737, Item I.C.5 for feedback of operating information. Staff review is documented in Inspection Report 50-412/87-18. This issue is closed.

Shift Supervisor Administrative Duties

The applicant has indicated that procedures will meet the intent of NUREG-0964, Item I.A.1.2 for shift supervisor administrative duties. Staff review is documented in Inspection Report 50-412/87-02. This issue is closed.

Verification of Correct Performance of Operating Activities

The applicant has indicated the procedures will meet the intent of NUREG-0737, Item I.C.6 for verifying the correct performance of operating activities. Staff review is documented in Inspection Report 50-412/87-18. This issue is closed.

Initial Test Program

The applicant has overall responsibility for development, supervision, performance, and documentation of startup proof, preoperational, and initial startup testing at BVPS-2. Responsibility through the first two phases (startup proof and preoperational testing) will be guided by the BVPS-2 Startup Group (SUG). When the initial startup testing phase commences at approximately 90 days before fuel load, the BVPS plant staff will assume responsibility for the remainder of the program. Vendors, contractors, and consultants will be involved in the three phases of the testing to varying degrees.

FSAR Section 14.2 describes the applicant's program for developing initial test procedures, conducting the test programs, and reviewing and evaluating test results in accordance with requirements under 10 CFR 50.34, Appendix B to 10 CFR 50, and Regulatory Guide (RG) 1.68, "Initial Test Programs for Water-Cooled Reactor Power Plants," Revision 2. Proof tests and much of the preoperational testing will be done by the BVPS-2 Startup Group. About 90 days before fuel load, the BVPS plant staff, under the coordination of the Plant Manager, will assume responsibility for control of the Startup and Test Program. The Startup Group will serve in a support role through completion of startup and testing.

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The Startup Manager, heading the Startup Group and reporting directly to the SVP, Nuclear Group, oversees administration and coordination of proof testing, preoperational and system operability verification testing, and startup testing.

Startup and testing activities are organized to include a number of independent review and control points. Within the group responsible for startup proof testing is the Independent Review Group which reviews test procedures and test results to ensure that applicable engineering requirements have been met. The Joint Test Group (JTG), chaired by the Startup Engineer, reviews test procedures, schedules, and results for the preoperational and startup phases of the BVPS-2 Startup and Test Program. The JTG consists of qualified representatives from the applicant, Stone and Webster (SWEC), and Westinghouse. The JTG shall function up to the time that the applicant has formally accepted BVPS-2 for commercial operation.

The Onsite Safety Committee will review and approve all tests involving reactivity control systems or engineered safeguard systems following initiation of fuel loading.

The minimum qualification of all personnel actively engaged in testing activities during the construction proof-test phase will be in accordance with RG 1.58 (August 1973), "Qualification of Nuclear Power Plants Inspection, Examination, and Testing Personnel." Supervisory personnel involved in the preoperational and initial startup test phases will meet minimum qualifications in accordance with RG 1.8 (March 1971), "Personnel Selection and Training."

It is the current staff position that individuals responsible for preoperational and startup testing activities for safety-related systems shall be qualified in accordance with the criteria as now stated in Section 4.4.6 of ANSI/ANS 3.1-1981. These criteria do not appear in the 1971 version of the standard endorsed by RG 1.8. Thus, the applicant should ensure that persons responsible for initial startup testing meet the current standard.

Summary and Conclusion

The applicant has described the programs and procedures that provide administrative controls over activities important to safety, including the control of the initial test program. The applicant meets SRP Section 13.5.1.

On the basis of the above review, the part of open issue 6 that covers Section 13.5 is closed.

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13.5.2 Operating and Maintenance Procedures

In discussing NUREG-0737, Item III.D.1.1, the SER stated that the applicant had not adequately addressed its program and related procedures aimed at minimizing reactor coolant leakage outside the containment. The staff also indicated that the applicant should include a description of the BVPS-2 program for minimizing postaccident leakage with its Procedures Generation Package (PGP). The staff clarifies that, while such a program is not part of the PGP, the objectives of the BVPS PGP are, for postaccident situations, consistent with the goals of a program satisfying NUREG-0737, Item III.D.1.1. By letter dated August 7, 1986, the applicant described the BVPS-2 Test Program to address NUREG-0737, Item III.D.1.1 and the SER concern. By letter dated August 7, 1986, the applicant described the BVPS-2 Test Program to address NUREG-0737, Item III.D.1.1 and the SER concern. The staff's review of the applicant's program indicates that exceptions to Item III.D.1.1 are not adequately justified, particularly in the comprehensiveness of the list of included plant equipment. The staff, therefore, requests the applicant to provide further information to resolve concerns with this issue. Resolution is not required for issuance of a plant license or for full-power operation, because preoperational testing will satisfy program requirements for the initial program interval. NUREG-0737, Item III.D.1.1 specifies that the maximum interval length not exceed each refueling cycle; therefore the staff requires that concerns associated with the BVPS-2 program be resolved before startup following the first BVPS-2 refueling outage; this will be tracked by licensing action TAC 62924. Preoperational tests will provide a satisfactory alternative during the initial program interval. Therefore, consideration of Technical Specification implementation of this program will be deferred until the first refueling outage. In conjunction with this, the applicant should retain any documentation that might be needed for NUREG-0737, Item III.D.1.1 program implementation. This closes confirmatory issue 41(a).

13.5.2.1 Emergency Operating Procedures Generation Package

After the accident at Three Mile Island Unit 2 (TMI-2), the staff developed the TMI Action Plan (NUREG-0660 and NUREG-0737) which required licensees of operating reactors to reanalyze transients and accidents and to upgrade emergency operating procedures (EOPs) (Item I.C.1). The plan also required the staff to develop a long-term plan that integrated and expanded efforts in the writing, reviewing, and monitoring of plant procedures (Item I.C.9). NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," represents the NRC staff's long-term program for upgrading EOPs, and describes the use of a Procedures Generation Package (PGP) to prepare EOPs. Submittal of the PGP was made a requirement by Generic Letter 82-33 (also designated Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability"). The generic letter requires each licensee and applicant to submit to the NRC a PGP which includes:

- plant-specific technical guidelines
- a writer's guide
- a description of the program to be used for the validation of EOPs
- a description of the training program for the upgraded EOPs

Criteria for the review of PGPs are in Standard Review Plan (SRP) Section 13.5.2. Further guidance is contained in NUREG-0899, the reference document for the EOP upgrade portion of Generic Letter 82-33.

By letters dated June 28 and July 16, 1984, the applicant submitted its original version PGP for Beaver Valley Power Station (BVPS) Units 1 and 2, respectively. Unit 1 is an operating plant; Unit 2 is still under construction. By letter dated April 8, 1987, the applicant provided a PGP with expanded information to be applicable to both units, and superseding the previous submittals for individual units. Therefore, the following evaluation through Section 13.5.2.2 applies to both Units 1 and 2. The PGP contained an introduction and the following sections:

- Initial Emergency Operating Procedure Development
  - Plant-Specific Technical Guidelines
  - Program for Verification/Validation
- EOP Administrative Controls Following Initial Implementation
  - Purpose
  - Applicability
  - Definitions
  - Responsibilities
  - References
  - Instructions
  - Appendices
  - Tables and Figures
- Writer's Guide
- Training Program Description
- Plant Comparisons
  - Reference Plant/BVPS Unit 1 Plant Comparison
  - Reference Plant/BVPS Unit 2 Plant Comparison
- References
- Tables and Figures
  - Flowpath for Preparing the Initial Draft of EOPs

Plant-Specific Technical Guidelines (P-STGs)

All licensees and applicants are required to submit P-STGs. These guidelines may be based on generic technical guidelines (prepared by the owner's group), or a plant-specific reanalysis of transients and accidents as described in TMI Action Plan Item I.C.1. In either case, the P-STG should be based on the identification of plant systems and functions, and be supported by an analysis of operator tasks to identify operator information and control needs. If generic technical guidelines are referenced, additional task specification may be needed depending on the level of task information provided by the generic technical guidelines and the nature of deviations from the guidelines. Examples of deviations that should be reviewed and documented are as follows:

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- any modifications to the mitigative strategy of the generic technical guidelines (e.g., for a Westinghouse plant, initial depressuration of the reactor coolant system (RCS) following a steam generator tube rupture without first having conducted a limited cooldown in accordance with the guidelines to establish a margin to saturation)

- differences in equipment operating criteria (e.g., RCP trip criteria, safety injection termination criteria).

- differences in equipment operating characteristics (i.e., between the plant-specific equipment and that assumed in the generic analyses, such as safety injection that can be throttled vs. only on/off)

- identification of methods and equipment used to address the technical areas of the generic guidelines that are specified as plant specific

- plant-specific setpoints or action levels that are calculated or determined in the manner other than specified in the generic technical guidelines

- actions that are taken in addition to those specified in the generic guidelines and that affect the mitigative strategy

- differences that affect the equipment's ability to adequately provide the necessary mitigative function

- use of different instruments or control parameters than those specified in the generic technical guidelines or determining instrumentation and control characteristics in a manner different than, or with a different basis than, that specified in the generic technical guidelines

- identification of items not covered by the NRC-approved generic technical guidelines (e.g., plant-specific conditions, equipment, operations, or bracketed [] information from the generic technical guidelines that relate to systems, functions or methods)

The purpose of the review of the technical guidelines submittal is to determine that the following general objectives are adequately addressed:

(1) The EOPs will be based on acceptable, validated technical guidelines derived from approved analyses of transients and accidents as described in NUREG-0660, Item I.C.1 and I.C.9, as clarified by NUREG-0737 and Supplement 1 to it, Item I.C.1. The P-STG, along with the generic guidelines (if referenced), and supporting documentation, provide EOP writers with all the technical information necessary for preparing EOPs which direct operators' actions to mitigate the consequences of transients and accidents without a need to first diagnose an event to maintain the plant in a safe condition (function orientation).

(2) The PGP describes an adequate method to identify information and control needs to be used as a basis for identifying control room instrumentation and controls necessary to perform the tasks specified in the technical guidelines.

The staff reviewed the P-STG program description to determine if it provided acceptable methods for accomplishing the objectives stated in NUREG-0899. The applicant will use Westinghouse Owners Group (WOG) Generic Emergency Response Guidelines (ERGs), Revision 1, dated September 1, 1983, as the technical guidelines from which plant-specific EOPs will be drafted. The applicant identified the following source documents for use in generating EOPs for the Beaver Valley Power Station:

- Westinghouse Owners' Group ERGs, Revision 1, dated September 1, 1983
- Westinghouse Owners' Group ERG background documents (procedure-specific and generic issues)
- BVPS final safety analysis reports
- BVPS Technical Specifications
- BVPS operating manuals
- previous EOP draft deviation sheets
- as-built plant drawings (e.g., P&ID, elementaries)
- additional information as appropriate

Recognizing that there are hardware differences between BVPS-1 and BVPS-2, deviation documentation associated with the PGP has been developed, and will be retained and maintained separately for each unit.

The applicant has committed to retain and maintain this expanded documentation for the lives of the units to augment the EOPs, to provide bases for the plant task analysis programs, and to provide reference for future EOP updates.

The applicant stated that based on comparisons and deviations discussed above, there are procedural variances to accommodate the hardware differences which are described. The applicant stated that there are no safety-significant deviations. The staff concludes that the basic mitigating objectives and strategies of the Westinghouse ERGs are incorporated in the BVPS PGP guidance and that the variances identified are not safety-significant changes.

The staff review of the Westinghouse Owners' Group ERGs is not complete; it should be noted that the applicant is still committed to revising its plant-specific guidelines and emergency procedures when the open issues in the generic review are resolved. Two examples of generic open issues that are applicable to Beaver Valley are:

(1) The Beaver Valley status trees do not identify "radioactivity control" as a critical safety function. This could lead to certain difficulties regarding the timely identification and diagnosis of steam generator tube ruptures, as was apparent during simulator exercises for other Westinghouse plants.

(2) For radiation-releasing scenarios, it is not clear how the Beaver Valley EOPs interface with the emergency action levels (EALs) of the site emergency plan.

From the staff's review and audit of a sample EOP and its supporting documentation, the staff finds that the BVPS P-STGs provide appropriate technical variance to account for plant-specific differences from the reference plant design.

On the basis of its review (discussed above), the staff finds that the plant-specific emergency procedures guidelines described in the BVPS PGP are technically acceptable for implementation. Concerns related to the treatment of SGTRs, provision of a radiation control safety function, and interaction with EALs will be pursued further, consistent with generic resolution of the WOG ERG long-term issues.

The BVPS P-STGs, expanded as committed, contain plant-specific technical information which is necessary as a reference to supplement to the EOPs, as a basis for the plant task analysis program, and as documentation of status in amending the P-STGs in the future.

In consideration of the above, the staff concludes that the technical content of the P-STGs is consistent with the requirements of SRP Section 13.5.2 and is, therefore, acceptable for implementation.

Writer's Guide

Applicants and licensee are required to submit a writer's guide that details the specific methods to be used in preparing EOPs which are based on the P-STGs. NUREG-0899 provides objectives and intent for the writer's guide. Because of the variety of available technical writing style guides and other references pertaining to the presentation of information, the specific information found in the writer's guide is expected to vary considerably among plants. For this reason, the staff did not perform a generic review of the human factors aspects of the Westinghouse Owner's Group ERGs. Each applicant or licensee has to submit a plant-specific writer's guide for review.

The purpose of the evaluation is to determine if acceptable methods are described for accomplishing the following general objectives:

- The writer's guide provides sufficient information for developing EOPs from the P-STG, which are usable, accurate, complete, readable, convenient to use, and acceptable to control room personnel.
- The writer's guide supports upgrading of the procedures and long-term consistency within and between procedures.

By letters dated June 28 and July 16, 1984, the applicant submitted PGPs for BVPS Units 1 and 2, respectively. By letter dated April 8, 1987, the applicant provided additional information defining a PGP which would apply to both units, including a commonly applied BVPS writer's guide.

On the basis of its review, the staff concludes that the Writer's Guide provides acceptable information for developing EOPs which are usable, accurate, complete, readable, convenient to use, and acceptable to control room personnel, and that the Writer's Guide meets the requirements of SPR Section 13.5.2, and therefore, is acceptable.

Program for Validation/Verification (V/V)

The purpose of evaluating the V/V program is to determine whether the applicant has provided evidence that the upgraded EOPs are technically correct, are written to accurately reflect the plant-specific Writer's Guide; are usable; correspond to control room/plant equipment; are compatible with minimum number, qualifications, training, and experience of operating staff; and provide a high level of assurance that the procedures will work as a component of the accident mitigation system.

In its submittals, the applicant described its V/V program. The program described in these three submittals is systematic and comprehensive. The staff concludes that the applicant has developed a V/V program that provides adequate assurance that EOPs are technically correct and usable; follows the Writer's Guide; corresponds to the control room/plant hardware; is compatible with the minimum number, qualifications, training, and experience of the operating staff; meets the requirements of SRP Section 13.5.2; and is, therefore, acceptable.

Program for Operator Training on EOPs

The purpose of evaluating the training program on EOPs is to ensure that operators understand the philosophy, mitigation strategies, and technical bases of the EOPs; and that operators have a working knowledge of the technical content of the EOPs, and are capable of successfully executing the EOPs under emergency conditions.

In its submittals, the applicant described a program of classroom and simulator training directly aimed at enabling operators to understand the structure, basis, and limitations of the EOPs and to provide a working knowledge of the technical content of the EOPs by practicing EOPs under simulated emergency conditions. The staff finds that the program is acceptable, and concludes that implementation of the described training program should result in the operators' understanding the philosophy behind the approach to the EOPs, understanding the mitigative strategy and technical basis of the EOPs, having a working knowledge of the technical content of the EOPs, and having the capability to execute the EOPs under operational conditions. The training program meets the requirements of SRP Section 13.5.2, and is, therefore, acceptable.

13.5.2.2 Conclusions

The staff finds the various aspects of Duquesne Light Company's PGP for Beaver Valley Power Station acceptable as stated above. This closes confirmatory issue 47.

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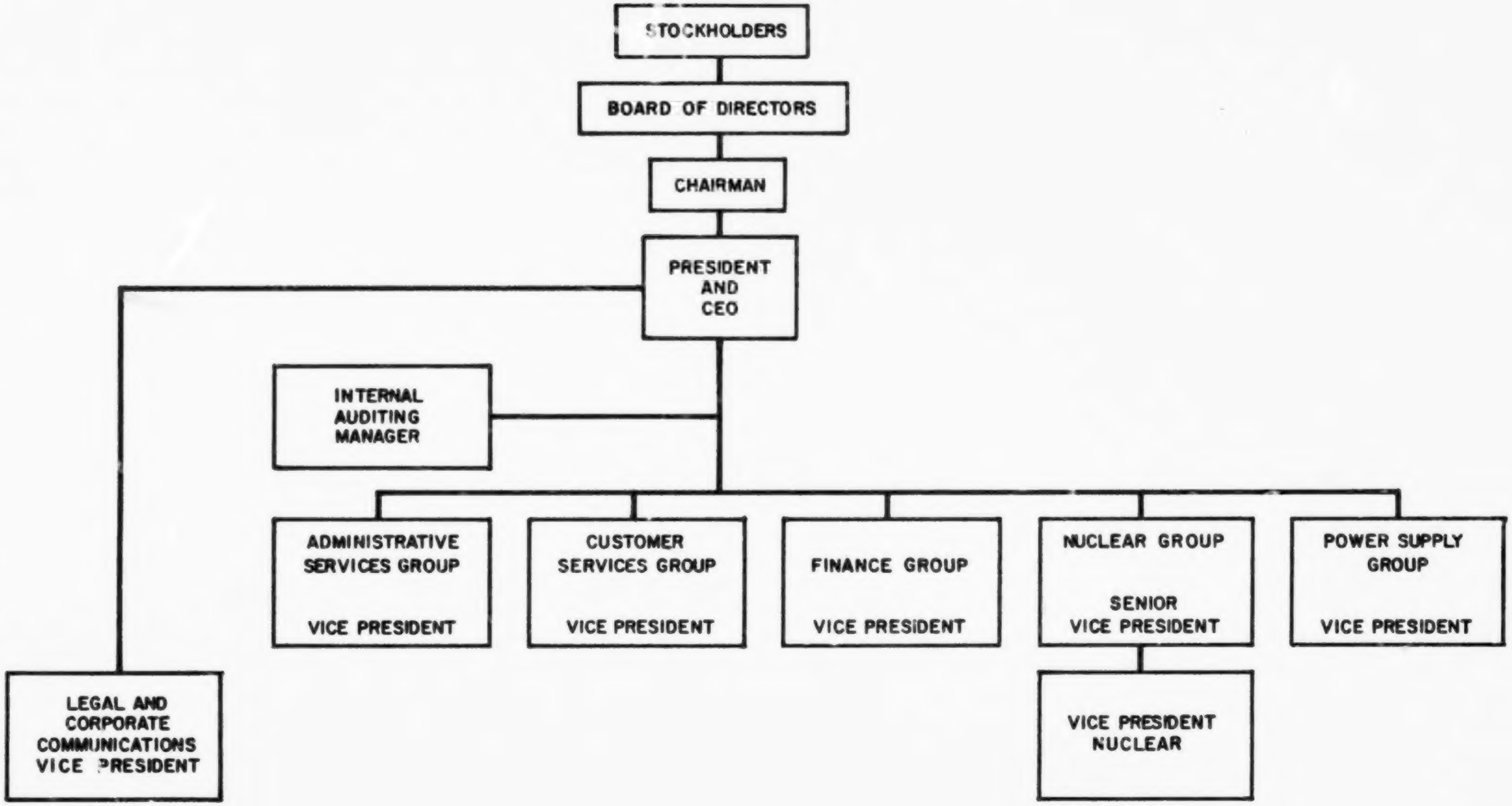
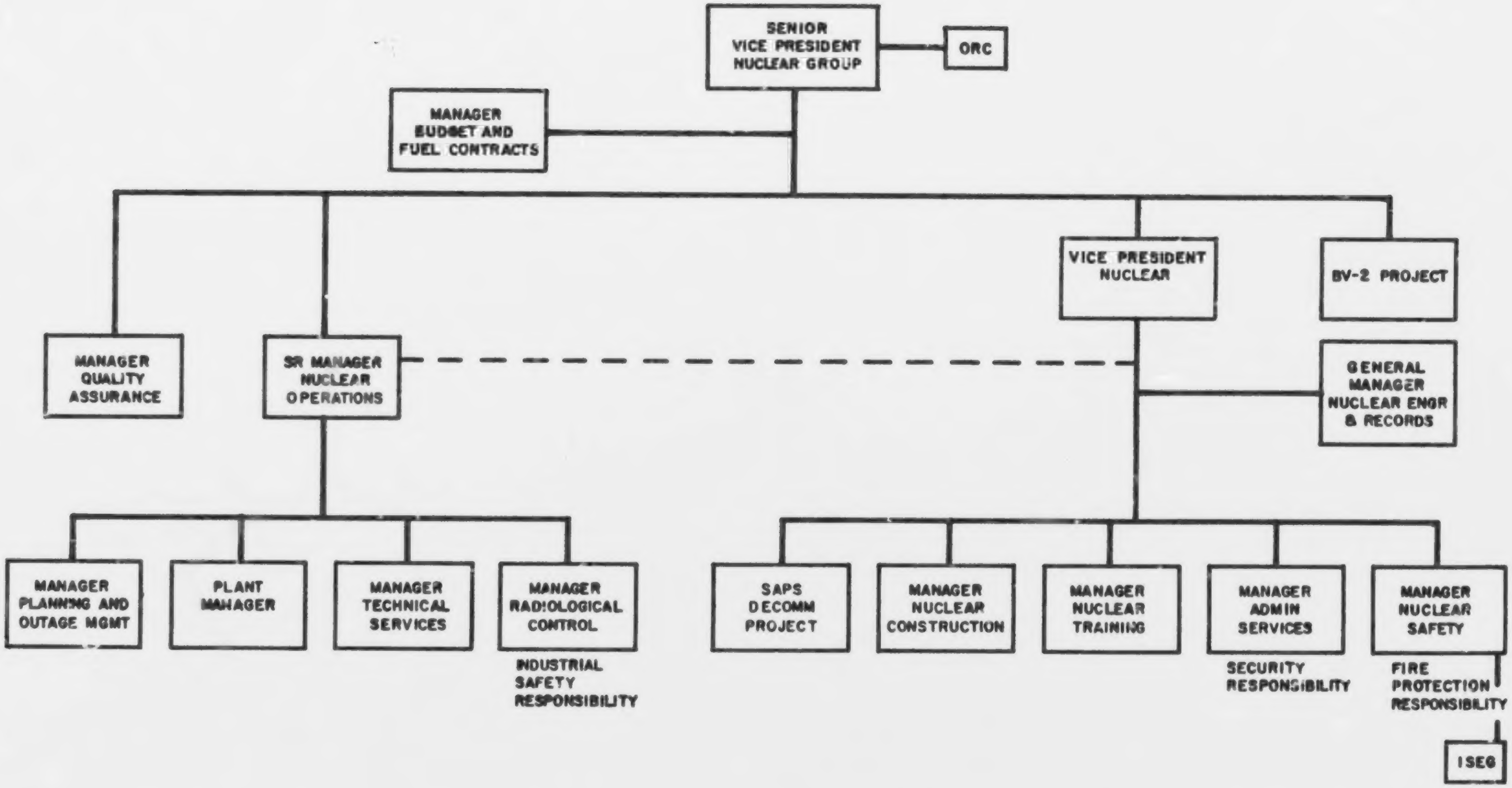

STOCKHOLDERS
BOARD OF DIRECTORS
CHAIRMAN
PRESIDENT AND CEO
INTERNAL AUDITING MANAGER
ADMINISTRATIVE SERVICES GROUP VICE PRESIDENT
CUSTOMER SERVICES GROUP VICE PRESIDENT
FINANCE GROUP VICE PRESIDENT
NUCLEAR GROUP SENIOR VICE PRESIDENT
POWER SUPPLY GROUP VICE PRESIDENT
VICE PRESIDENT NUCLEAR
LEGAL AND CORPORATE COMMUNICATIONS VICE PRESIDENT

Figure 13.1 Corporate structure, Duquesne Light Company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ORC
MANAGER BUDGET AND FUEL CONTRACTS
VICE PRESIDENT NUCLEAR
BV-2 PROJECT
MANAGER QUALITY ASSURANCE
SR MANAGER NUCLEAR OPERATIONS
GENERAL MANAGER NUCLEAR ENGR & RECORDS
MANAGER PLANNING AND OUTAGE MGMT
PLANT MANAGER
MANAGER TECHNICAL SERVICES
MANAGER RADIOLOGICAL CONTROL
INDUSTRIAL SAFETY RESPONSIBILITY
SAPS DECOMM PROJECT
MANAGER NUCLEAR CONSTRUCTION
MANAGER NUCLEAR TRAINING
MANAGER ADMIN SERVICES
SECURITY RESPONSIBILITY
MANAGER NUCLEAR SAFETY
FIRE PROTECTION RESPONSIBILITY
ISEG

Figure 13.2 Duquesne Light Company Nuclear Group

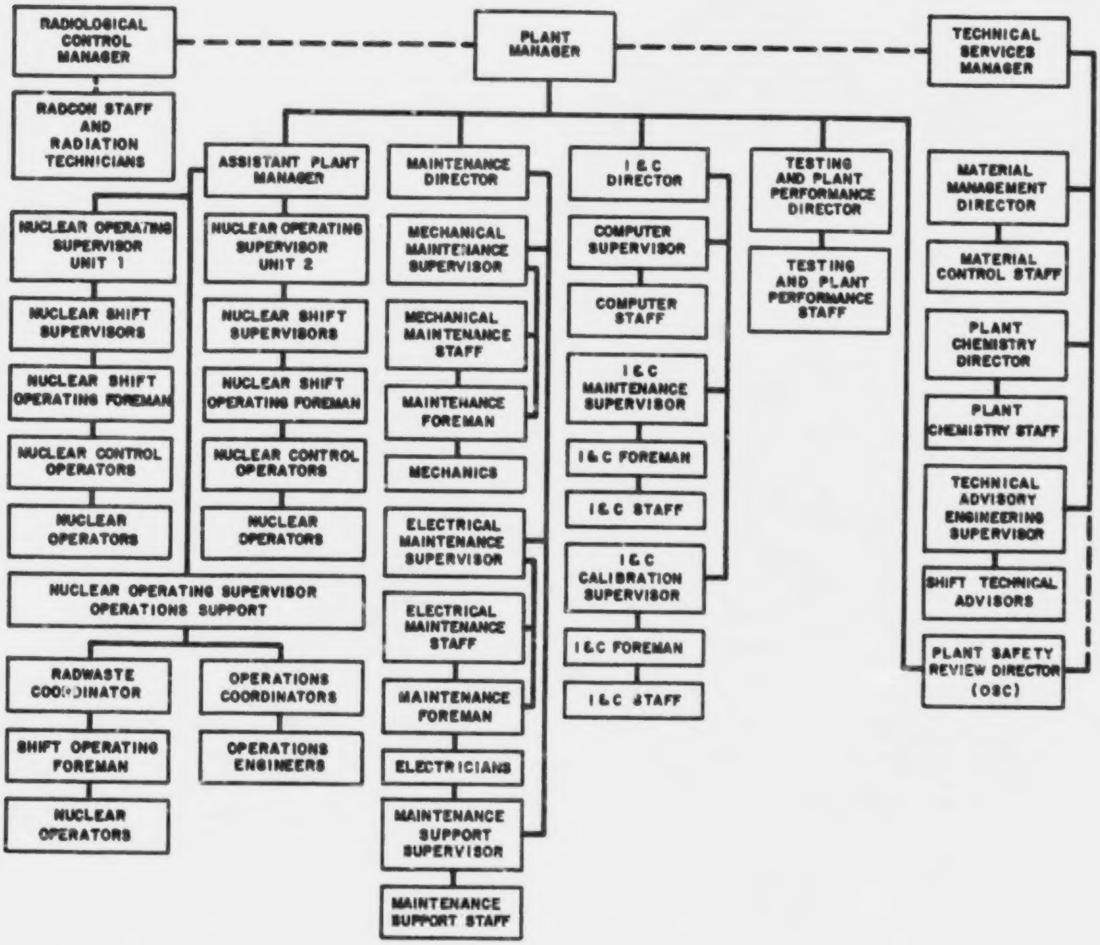
RADIOLOGICAL CONTROL MANAGER
PLANT MANAGER
TECHNICAL SERVICES MANAGER
RADCON STAFF AND RADIATION TECHNICIANS
ASSISTANT PLANT MANAGER
MAINTENANCE DIRECTOR
I & C DIRECTOR
TESTING AND PLANT PERFORMANCE DIRECTOR
MATERIAL MANAGEMENT DIRECTOR
NUCLEAR OPERATING SUPERVISOR UNIT 1
NUCLEAR SHIFT SUPERVISORS
NUCLEAR SHIFT OPERATING FOREMAN
NUCLEAR CONTROL OPERATORS
NUCLEAR OPERATORS
NUCLEAR OPERATING SUPERVISOR UNIT 2
NUCLEAR SHIFT SUPERVISORS
NUCLEAR SHIFT OPERATING FOREMAN
NUCLEAR CONTROL OPERATORS
NUCLEAR OPERATORS
NUCLEAR OPERATING SUPERVISOR OPERATIONS SUPPORT
RADWASTE COORDINATOR
SHIFT OPERATING FOREMAN
NUCLEAR OPERATORS
OPERATIONS COORDINATORS
OPERATIONS ENGINEERS
MECHANICAL MAINTENANCE SUPERVISOR
MECHANICAL MAINTENANCE STAFF
MAINTENANCE FOREMAN
MECHANICS
ELECTRICAL MAINTENANCE SUPERVISOR
ELECTRICAL MAINTENANCE STAFF
MAINTENANCE FOREMAN
ELECTRICIANS
MAINTENANCE SUPPORT SUPERVISOR
MAINTENANCE SUPPORT STAFF
COMPUTER SUPERVISOR
COMPUTER STAFF
I & C MAINTENANCE SUPERVISOR
I & C FOREMAN
I & C STAFF
I & C CALIBRATION SUPERVISOR
I & C FOREMAN
I & C STAFF
TESTING AND PLANT PERFORMANCE STAFF
MATERIAL CONTROL STAFF
PLANT CHEMISTRY DIRECTOR
PLANT CHEMISTRY STAFF
TECHNICAL ADVISORY ENGINEERING SUPERVISOR
SHIFT TECHNICAL ADVISORS
PLANT SAFETY REVIEW DIRECTOR (OSC)

Figure 13.3 Duquesne Light Company Beaver Valley facility organization

Table 13.1 Minimum shift crew composition

Mode	Unit 1	Unit 2	Common facility
In Modes 1, 2, 3, or 4	1 NSS (SRO) 1 NSOF (SRO) 2 NCO (RO) 2 NO (non-licensed)	1 NSS (SRO) 1 NSOF (SRO) 2 NCO (RO) 2 NO (non-licensed)	1 STA 2 RT 1 CA
Total shift crew	6	6	4
In Modes 5 or 6	1 NSS or NSOF (SRO) 1 NCO (RO) 1 NO (non-licensed) 1 RT 1 SRO (refueling operation only)	1 NSS or NSOF (SRO) 1 NCO (RO) 1 NO (non-licensed) 1 RT 1 SRO (refueling operation only)	
Total shift crew	5	5	

Note:

Positions:

Nuclear Shift Supervisor - NSS
Nuclear Assistant Shift Operations Foreman - NSOF
Nuclear Control Operator - NCO
Nuclear Operator - NO
Radiation Technician - RT
Chemist or Chemical Analyst - CA

NRC Licenses:

Senior Reactor Operator - SRO
Reactor Operator - RO

14 INITIAL TEST PROGRAM

By letters dated April 6 and May 12, 1987; three letters dated May 21, 1987; two letters dated May 25, 1987; and a letter dated May 26, 1987, the applicant proposed acceptable resolution to the following issues:

FSAR Section 14.2.12.12.6 - Accumulator Isolation Valve Tests

By item 2 of a letter dated May 26, 1987, the applicant committed to the safety injection of test accumulator discharge isolation valves after fuel load, but before criticality, to conform to the preoperational testing guidance provided in Regulatory Guide (RG) 1.79. The applicant's commitment is acceptable to the staff.

By FSAR Amendment 13, the applicant stated that the system test supervisor is authorized to approve the substitution of data collected during another test if the acceptance criteria are equal as determined by the applicant's Joint Test Group. This follows the guidelines of RG 1.68 and is, therefore, acceptable to the staff.

FSAR Section 14.2.12.17.1 - Computer Input and Printout Data Test

The applicant proposed to delete the staff-approved SOV-2.05A.01 because the equivalent testing was performed using IOPs 27-IHC-5A-2.01 through 27-IHC-5A-2.22 and was approved by the applicant's Joint Test Group. Therefore, the applicant's commitment is acceptable to the staff.

FSAR Section 14.2.12.52.4 - Containment Instrument Air Design Verification Test

By item 1 of a letter dated May 26, 1987, the applicant committed to perform the containment instrument air system test after fuel load but before criticality, to conform to the preoperational testing guidance provided in RG 1.68. The applicant's commitment is acceptable to the staff.

FSAR Section 14.2.12.54.1 - Normal AC Power Distribution System Test

The applicant proposed to delete the staff-approved SOV-2.36A.01 and substituted IOPs 27-GMS-35B-2.01 through 27-GMS-35B-2.06 and 27NNS-36A-2.01 through 27NNS-36A-2.15, which have equivalent acceptance criteria and were approved by the applicant's Joint Test Group. Details of tests conducted are described in paragraph 5 of the applicant's letter dated May 21, 1987. The applicant's commitment is acceptable to the staff.

FSAR Section 14.2.12.72.1 - Deletion of the Seismic Instrumentation Test

The applicant proposed to delete the staff-approved SOV-2.45B.01 because startup Proof Test Procedure 2T-SRM-45B.2.01, "Initial Startup Test of the Strong Motion Seismic Instrumentation System," has equivalent acceptance criteria and was approved by the applicant's Joint Test Group. The applicant's commitment is acceptable to the staff.

FSAR Section 14.2.12.14.4 - Low-Power Physics Test - Deletion of the Shutdown Margin Calculation From This Test

The applicant proposed to verify the shutdown margin calculation by the method described in paragraph 7 of its letter dated May 21, 1987. The applicant's commitment is acceptable to the staff.

FSAR Section 14.2.12.2.9 - Rod Cluster Control Assembly (RCCA) Bank and Boron Worth Measurement

This section was deleted and the item was incorporated into FSAR Section 14.2.12.4.4. The applicant proposed this action because rod worth measurement will be taken using the rod swap method. The rod swap measurements will be incorporated into the staff-approved IST-2.02,03, "Low-Power Physics Test." The applicant references Westinghouse document WCAP-11384, previously approved by the staff.

FSAR Section 14.2.12.53.1 - Main Generator Tests

These tests were changed to delete references to the transformer cooling system tests. By item 2 in its letter dated May 26, 1987, the applicant proposed to reinstate the transformer cooling systems as a part of the main generator tests to be performed at 50% and 100% reactor power by STP-2.35.01, "Main Transformer Test." These commitments are acceptable to the staff.

FSAR Test Abstract 14.2.12.66.2 - Containment Air Recirculation System Test During the Hot Functional Test

The applicatn, by its test abstract 14.2.12.66.2 committed to performing this test at 50% and 100% power, thereby deleting a test at 5% power as recommended by RG 1.68, Appendix A.4.j. By letter dated May 21, 1987, the applicant proposed to reinstate the 5% low-power test to conform to the guidance provided by RG 1.68 and by Figure 14.2-3 of the abstract which presently shows testing at 5%, 50%, and 100% power. These commitments are acceptable to the staff.

FSAR Section 14.2.12.8.13 - Pressurizer Heater and Spray Capability Test (IST)

By Attachment I to its letter dated April 6, 1987, the applicant has revised this test. This revision incorporates the commitment of FSAR Table 1.10-1, Item I.G.1(2) Amendment 5 in accurately describing the contents of IST-2.06.2, "Pressurizer Heater and Spray Capability Test." These commitments are acceptable to the staff.

FSAR Confirmatory Issue 52(c) - Plant Performance Following MSIV Closure at 100% Power Test

The applicant has proposed to perform this test at 30% power without providing justification for not testing at 100% power. By its letter dated May 21, 1987, the applicant provided adequate justification for not performing this test at 100% power, which is acceptable to the staff. These commitments close out confirmatory issue 52(c).

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By FSAR Amendment 15, the applicant made the following changes to its Initial Test Program:

(1) Clarified test prerequisites, methods, and acceptance criteria in FSAR test abstracts 14.2.12.4.5, "Power Coefficient Measurement"; 14.2.12.12.2, "Safety Injection Check Valve Test"; 14.2.12.12.3, "Safety Injection Flow Test"; 14.2.12.15.1, "Recirculation Spray System Pumps and Controls Test"; 14.2.12.48.1, "Main Plant Carbon Dioxide Fire Protection System Test"; and 14.2.12.52.5, "Response of AOVs to Loss of Instrument Air." Because these changes will demonstrate the purposes and requirements of the Initial Test Program, the staff finds them acceptable.

(2) Changed the title of the Vice President-Nuclear Group to the Senior Nuclear Group Vice President, and deleted the word "Station" in the titles of the Nuclear Station Operations Group, the Nuclear Station Operations Group Supervisor, and the Nuclear Station Operating Supervisor. Because these are changes in title only and do not affect reporting relationships or job responsibilities, the staff finds them acceptable.

(3) Provided justification for deleting the extraction steam system test and the computer operability test. Because the functions examined by these tests are not important to safety, the staff finds their deletion acceptable. This closes out confirmatory issue 52(d).

This review was performed with the assistance of personnel from Battelle Pacific Northwest Laboratories.

15 ACCIDENT ANALYSIS

15.2 Decrease in Heat Removal by the Secondary System

15.2.6 Loss of Nonemergency AC Power to the Station Auxiliaries

In the SER, the staff stated that during the transient involving the loss of nonemergency ac power to the station auxiliaries, the feedwater comes from the primary plant demineralized water storage tank (PPDWST). With makeup water from the demineralized water storage tank, this provides enough water to reduce the hot-leg temperatures to 350°F for this transient.

However, in FSAR Amendment 12, the applicant revised the usable PPDWST volume to be approximately 127,500 gallons. In SSER 4, the staff found that a PPDWST inventory of 127,500 gallons was acceptable. Furthermore, the staff concluded that the service water system may serve as a safety-related, long-term, backup source of auxiliary feedwater for the steam generators. On this basis, the staff finds that a sufficient water supply is still being provided to reduce the hot-leg temperatures to 350°F for the above-cited transient.

15.6 Decrease in Reactor Coolant Inventory

15.6.3 Steam Generator Tube Rupture

In the SER, the staff stated that it had previously questioned the assumption made in the steam generator tube rupture (SGTR) analysis that the affected steam generator can be isolated in 30 minutes. In response, the applicant stated that the Westinghouse Owners Group (WOG) would address SGTR licensing concerns through generic evaluations. The WOG SGTR Subgroup analyses include evaluation of the probability and consequences of steam generator overfill, the worst single active failure, and the necessary operator action times. The WOG submitted: (1) WCAP-10698, "SGTR Analysis Methodology to Determine Margin to Steam Generator Overfill," in December 1984; (2) Supplement 1 to WCAP-10698, "Evaluation of Offsite Radiation Doses for SGTR Accident," in May 1985; and (3) WCAP-11002, "Evaluation of the Steam Generator Overfill Due to SGTR Accident," in February 1986. The staff has completed its review of Supplement 1 to WCAP-10698 and concludes that plant-specific radiological consequence analyses are still required.

The staff will prepare a generic safety evaluation report which will include evaluation of the SGTR system analyses and assumed operator action times in WCAP-10698 and WCAP-11002. The staff will also require plant-specific information including radiological consequence analyses, analyses of steamline static load in the event of overfill, and a listing of systems and components credited in the analyses to mitigate accident consequences, including justification of their use if they are not safety grade. By letter dated April 13, 1987, the applicant provided a commitment to comply with generic requirements which would result from resolution of this issue.

The staff has determined that the low probability of a design-basis SGTR accident during the first cycle of operation offers reasonable assurance that Beaver Valley Unit 2 can operate for one cycle until this issue is resolved.

On the basis of the applicant's commitment, confirmatory issue 43 is closed; the completion of this issue will be tracked by licensing action TAC 62929.

15.8 Anticipated Transients Without Scram

Status of Salem ATWS Event Issues

On July 8, 1983, the NRC issued Generic Letter (GL) 83-28 as a result of the anticipated-transient-without scram (ATWS) events at Salem Nuclear Generating Station. This letter addressed actions to be taken by licensees and applicants to ensure that a comprehensive program of preventive maintenance and surveillance testing is implemented for the reactor trip breakers in pressurized-water reactors.

The staff has completed its review of the bulk of the applicant's response to GL 83-28 and has documented its results in appendices to the SER. The following list serves to record completed staff reviews, and shows where individual safety evaluations may be found:

- Item 1.1, Post-Trip Review (Appendix K, SSER 1)
- Item 2.1, Equipment Classification and Vendor Interface (Reactor Trip System Components) (Appendix L, SSER 2 and SSER 4)
- Items 3.1.1 and 3.1.2, Post-Maintenance Testing Reactor Trip System Components (Appendix O, SSER 4)
- Items 3.1.3 and 3.2.3, Post-Maintenance Testing in Technical Specification That Could Degrade Safety (Appendix M, SSER 2)
- Items 3.2.1 and 3.2.2, Post-Maintenance Testing--All Other Safety-Related Components (Appendix O, SSER 4)
- Items 4.1, Trip System Reliability (Appendix J, SSER 1)
- Items 4.2.1 and 4.2.2, Preventive Maintenance Program for Reactor Trip Breakers--Maintenance and Trending (Appendix J, SSER 1)
- Item 4.5.1, Reactor Trip System Reliability--System Functional Testing (Appendix O, SSER 4)
- Item 4.5.2, Reactor Trip System Reliability--On-line Testing (Appendix N, SSER 4)

The remaining issues of GL 83-28 are under review. Their resolution is not a requirement to issuance of an operating license. These will continue to be tracked by licensing actions TAC 62950, 62951, 62952, 62955, 62956, and 62958.

15.9 TMI Action Plan Requirements

15.9.2/15.9.3 II.K.1 I&E Bulletins on Measures to Mitigate Small-Break LOCAs/Loss-of-Feedwater Accidents

In the SER, the staff indicated that it would evaluate measures to satisfy Items II.K.1.5 and II.K.1.10 when they were completed. By letter dated April 29, 1987, the applicant notified the staff of the completion of various operating manual chapters to address NUREG-0737 Items II.K.1.5 and II.K.1.10. The staff confirmed the adequacy of these measures by observation on April 15, 1987 (Inspection Report 87-18), and finds that this resolves confirmatory issue 41(b).

15.9.9 II.K.3.5 Automatic Trip of Reactor Coolant Pumps During a LOCA

By letters dated November 15, 1985 and March 10, 1986 the applicant provided information on this issue, which is tracked as confirmatory issue 41(c). The staff has completed its review of the applicant's letters and issued an interim report on April 22, 1986. The interim report also documented the staff's additional information need to complete the review. By letter dated April 22, 1987, the applicant submitted the requested information. The staff's review is continuing; preliminary review shows that the applicant has addressed the issues raised in the staff's April 22, 1986 interim report. This issue will be completed for full-power operation (see the staff's letter dated April 22, 1986). The staff will report its findings in a future report.

15.9.11 II.K.3.17 Report on Outage of ECCS

In the SER, the staff stated that the applicant has committed to meet the intent of this item when the operating and maintenance procedures are written. By letter dated April 1, 1987, the applicant stated that Station Administrative Procedure (SAP) 30 provides for compiling statistics for outages of emergency core cooling system (ECCS) components. SAP 30 has been approved by the applicant and will be issued following necessary training of personnel. Furthermore, the staff's Inspection Report 50-412/87-02 documents the completion of this procedure.

On the basis of the applicant's commitment and the completion of the procedure, confirmatory issue 41(d) is considered closed and its implementation is considered complete.

17 QUALITY ASSURANCE

17.5 Independent Design Verification Program

17.5.1 Background

In a meeting with the NRC on March 15, 1986, the applicant proposed a two-phase Engineering Assurance (EA) Program for the Beaver Valley Power Station, Unit 2 in lieu of an Independent Design Verification Program. The first phase consisted of four in-depth technical audits, three of which had been previously performed and a fourth technical audit to be completed with NRC oversight. The second phase provided for an evaluation and assessment of the results of the four audits in order to form conclusions as to the adequacy of the Stone and Webster Engineering Corporation (SWEC) design process as implemented for the applicant.

The fourth audit, designated Audit No. 52, further assessed the adequacy of the design process at Beaver Valley Unit 2 by evaluating the design of the safety injection system (SIS), the adjoining portion of the recirculation spray system (RSS) used to supply water to the core to provide long-term cooling, and associated interfaces. The staff participated in selecting the scope of the fourth audit along with the applicant and SWEC. The staff and the applicant mutually agreed on the scope and depth of review of this audit before it began. Audit No. 52 was performed by qualified engineers of SWEC who had not previously worked on the Beaver Valley Unit 2 project. The scope of Audit No. 52 was selected to minimize review of areas that had previously been the subject of in-depth technical audits performed by SWEC or the applicant, particularly SWEC Audit No. 50 (Beaver Valley Unit 2 Hazards Analysis Program), SWEC audit No. 44 (fuel pool cooling and cleanup plus portions of the fuel building), the SWEC audit of the Site Engineering Group (SEG), and the applicant's Design Basis Endorsement (DBE) Program and resulting confirmation programs.

The applicant's DBE Program had been self-initiated by its Nuclear Construction Division. The DBE Program confirmed that the SWEC design documents correctly incorporated FSAR commitments and that the commitments and criteria specified in the design documents were properly incorporated in the plant design by verifying the installed design of the residual heat removal and the auxiliary feedwater systems.

The staff focused its inspection efforts on Audit No. 52, and conducted additional inspections on Audit Nos. 44 and 50 and the DBE Program. The following NRC inspections were conducted as shown in Figure 17.1:

Audit	Date	Inspection activity	NRC Report No.
No. 52	4/24/86	Site inspection	86-09
No. 52	4/28-4/30/86	Audit preparation	86-09
No. 52	6/2-6/6/86	Plan implementation	86-17
No. 44	7/28-7/30/86	Corrective action	86-23
No. 50	7/28-7/30/86	Corrective action	86-23
DBE	8/4-8/5/86	Corrective action	86-23

In each of the above inspections, NRC inspectors aided by contractors reviewed the design documents prepared by the technical disciplines of mechanical systems, mechanical components, electrical power, instrumentation and controls, and civil/structural. Reports were prepared for each inspection which addressed the respective inspection activities and closed out previous NRC inspection concerns, where appropriate. Additionally, the staff reviewed corrective actions taken by SWEC to address findings and recommendations of previous inspections. This review was conducted at the offices of SWEC from September 22 to 25, 1986, and provided additional information which formed the basis for closure of technical items discussed herein.

17.5.2 Engineering Assurance In-Depth Technical Audits

Senior level SWEC personnel performed Audit Nos. 44, 50, and 52 as well as the SEG audit. The team of technical specialists functioned under the direction of the SWEC Engineering Assurance Division, Boston. Experienced off-project personnel from appropriate disciplines were utilized. Comparable technical expertise was employed on the applicant's DBE Program.

The Phase I portion of the audit program represents the efforts of teams of qualified personnel reviewing numerous documents over a period of time from November 1983 to July 1986. Where problems or concerns were identified, action items (AIs) were generated. Audit observations were issued to track continuing action on those AIs for which corrective actions were not complete at the end of the audit. Further information concerning the audit observations as well as additional information requested by the NRC was subsequently provided in the Phase II report for evaluation of in-depth technical audit results for Beaver Valley Unit 2, dated December 16, 1986.

The scope and content of Audit No. 52 was developed to complement as well as supplement the audit activities performed before its inception. The plant systems evaluated were the SIS and the portion of the adjoining RSS which functions during the recirculation mode of high-head safety injection. The SIS represents a system for which the basic design was within the scope of the nuclear steam supply system (NSSS) supplier, Westinghouse, and for which the detailed arrangement and integration into the overall power plant design, including pipe stress and component support analyses, were the responsibility of SWEC. The RSS represents a system for which the total design responsibility and procurement was the responsibility of SWEC. These systems provided a representative sample of the design process at Beaver Valley Unit 2 since the systems perform safety-related functions, contain multidiscipline inputs and involvement, contain various types of components, interface with other systems, have different modes of operation, and were in the as-built reconciliation phase of construction.

In order to add certain attributes and provide adequate coverage of some design considerations not addressed in previous technical audits, it was necessary to go beyond the sample systems in certain areas including:

- structural load tracking
- cable tray and conduit supports
- as-built stress reconciliation

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- environmental qualification
- ac and dc power distribution
- high-energy line break safe shutdown evaluations
- seismically induced interactions between safety-related and non-safety-related structures and components
- internally generated missiles

Open items which were not resolved from the previous technical audits on Beaver Valley Unit 2 were included in Audit No. 52. A descriptive listing of all discrepancies observed during theses audits was developed. In order to ensure that the audit team was sensitive to conditions previously observed, each EA auditor was provided with a descriptive listing of earlier findings for review.

The Hazards Analysis Program audit was performed at Beaver Valley Unit 2 between November 1985 and January 1986. Since some parts of the program had not been fully implemented at the time of that audit, Audit No. 52 provided the supplemental evaluation for these areas including internally generated missiles, seismically induced interactions between safety-related and non-safety-related structures and components, and safe-shutdown analysis.

It should be noted that although the scope of Audit No. 52 was generally applicable to certain systems, structures, and components, many of the FSAR commitments, SWEC procedural requirements, design criteria, specifications, and drawings requirements covered in this audit also applied to all Beaver Valley Unit 2 safety-related systems, structures, and components. For example, the electrical design criterion which was applied to all electrical systems was validated by comparing it against the FSAR to verify that the appropriate licensing commitments and regulatory requirements had been incorporated. Another example is the review of procedures and criteria utilized in pipe stress analysis and pipe support design. These procedures applied to all safety-related systems.

In Phase II, audit findings contained in four Engineering Assurance Division (EAD) technical audits (Nos. 44, 50, 52, and the SEG audit from April 23 to June 20, 1984) were itemized, categorized, and coded according to a formal plan. Categorization consisted of assigning codes to define the specific nature of each finding. These codes were: finding type, document type, responsible discipline, corrective and preventive action, cause, extent of condition, and an exclusion code that was used to establish the potential consequences of a finding. Information on coding sheets was then inserted in a computerized data base for composite analysis of the data. Data base information was sorted into finding type subcategories and each subcategory was reviewed for common features and significance of occurrence. The Phase II results were documented in a formal report dated December 16, 1986.

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17.5.3 Engineering Assurance Conclusions

Phase I

The SWEC EA Technical Audits reached conclusions about the adequacy of the design and design process at Beaver Valley Unit 2 relative to the systems reviewed and the overall plant. The conclusions of the EAD are given in detail, and the bases for the conclusions developed in the various audit reports are included. The discrepancies identified during the audits were studied and evaluated both individually and collectively; none were attributed to an overall programmatic or systematic weakness. The EAD concluded that the implementation of the design process was adequate in most areas. Discrepancies observed were mostly limited or random instances of incomplete compliance to individual procedural requirements. The overall conclusions may be summarized as follows:

(1) The conclusions were developed on the basis of a large scope of review (both the number of areas and documents reviewed as well as detail and depth of the effort).

(2) Apparent and identified discrepancies were evaluated individually and were studied collectively.

(3) In most of the areas studied, implementation of the design process was determined to be adequate. In instances where discrepancies were observed, they were generally limited to incomplete compliance of procedural requirements.

(4) Specific corrective actions were instituted for all discrepancies and when programmatic weaknesses were found, overall comprehensive solutions were developed and implemented.

Phase II

The Phase II evaluation assessed the collective significance of the findings of the Phase I audits to determine if the findings indicated the existence of an adverse trend or trends that could raise concerns about the adequacy of the SWEC design process. On the basis of the evaluations conducted in Phase II, the EAD concluded that the audits conducted in Phase I by SWEC and the applicant provide additional assurance that the overall design of Beaver Valley Unit 2 is technically adequate and no adverse trends were detected that could call into question the adequacy of the design or design process. This conclusion was based on:

(1) the total scope of the audits performed and the depth of reviews conducted

(2) the level of audit review as reflected in the detail of the audit findings

(3) investigation of all audit findings (regardless of significance), the action taken to bound and correct the condition, and the action taken to prevent recurrence

(4) no indication of discrepancies in areas not audited being of any greater importance or occurring in any greater frequency than the audited areas

17.5.4 Assessment by the NRC Staff

As identified in Section 17.5.1, the NRC conducted several inspections in monitoring the engineering assurance program at Beaver Valley Unit 2. These inspections were conducted at the Beaver Valley Unit 2 site or at SWEC's offices in Boston, Massachusetts. On the basis of the reviews during these inspections, the following staff assessment is presented. Unless otherwise indicated, all staff comments refer to Audit No. 52.

17.5.4.1 FSAR Changes

The following AIs were resolved on the basis of a commitment made by the applicant to submit proposed FSAR changes to the NRC. The AIs in this category are: C01, C03, C06, C07, C22, C45, E03, E04, E05, E08, E09, M01, M02, M03, P07, P10, S01, S03, S07, S12, and Item 1.3 of Audit No. 44. The proposed FSAR changes have been submitted by the applicant in Amendments 13, 15, and 16.

17.5.4.2 Technical Assessments

The following is the assessments by the staff of each technical discipline:

Mechanical Discipline

In the power discipline (mechanical systems design), 16 AIs were identified; in the engineering mechanics discipline (mechanical components), 35 were identified. The following staff comments are provided relative to these AIs.

Mechanical Components. Action Item M-18 identified a concern that two parallel snubbers (pipe support calculation No. 2SIS-PSSP-201A, B) which were connected to form a structural support with unequal stiffnesses had not been qualified properly. In this situation, each snubber support assembly must be designed either to carry the entire load, or the actual load must be accurately determined. The applicant indicated that the snubbers had been designed to carry the full load but did not provide an explanation to this effect in the calculation. As part of the resolution for this finding, other comparable snubber supports were reviewed. It was determined that there were 34 other parallel snubber supports with unequal stiffnesses and a review found that the snubber supports are acceptable. In addition, the applicant has provided additional guidance to the stress analysis; this should preclude a recurrence of the problem. The staff has reviewed the approaches to be used and has determined that the original concerns have been adequately addressed. This item is closed.

Action Item M-20 involved the use of a hydraulic snubber to restrict the axial motion of a piping system resulting from the effects of waterhammer. The reason for the use of a hydraulic snubber, in lieu of a mechanical snubber, is discussed in calculation No. 12241-NP(N)-X79P which indicated that a hydraulic snubber was used because a mechanical snubber is unable to restrict axial movement to within required limits. However, the calculation did not address the functional ability of the hydraulic snubber to resist hydrodynamic forces applied over a long period of time. To resolve this matter, the applicant identified and reviewed all other similar situations and issued procedural instructions aimed at preventing a recurrence. The snubbers reviewed were in all cases found to be adequately designed. The staff has reviewed the implementation of the corrective actions and considers them to be adequate; this item is, therefore, closed.

Action Item M-26 concerned calculation No. 12241-NB(B)-22-HBB which addresses the qualification of the support for the recirculation spray cooler. The original EA team was concerned that the torsional and bending effects of the vertical tapered cantilevered plates were not addressed in the calculation. The applicant responded by revising the calculation to include the determination of the torsional and bending stresses. However, the actual manner in which the support resists load and the adequacy of the tapered cantilever plates to resist buckling were not addressed. The applicant has revised the calculation to clarify the actual loading that will occur at the support's upper and lower restraints by accounting for support flexibility and to address the local structural effects, particularly the local buckling of the vertical tapered plates of the support. All structural components were found to be adequate. The staff reviewed the technical approach and calculation procedures employed and concurred that the scope of this item has been adequately addressed. This item is closed.

Action Item M-31 addressed an apparent inconsistency between the assumed weight of a pair of orifice flanges used in pipe stress analysis and the actual weight. When piping is analyzed, all concentrated weights must be considered in accordance with the requirements of the applicant's "Design Criteria Document for Pipe Stress, Pipe Supports, Duct Supports, Tubing and Tubing Supports" (2BVM-157, dated February 1986). The applicant's response confirmed that the weight had originally been underestimated. As part of the remedial action taken, other piping was analyzed and similar errors were found. The applicant has resolved this matter by issuing instructions to all stress analysts specifically delineating the procedures to follow to ensure that proper flange weights are used. The applicant has committed to reevaluate this matter during the program to reconcile as-built piping. The staff considers this response to be adequate since the effect of the variation between weights used in analysis and actual weights does not materially affect the qualification of the piping. This item is closed.

Action Item M-32 concerned the traceability of shop fabrication information required to determine stress intensification factors (SIFs) at branch and run intersections. Response from the applicant showed that the information was controlled and that the pipe stress analyst could retrieve it when required. In particular, it was documnted that for isometric drawing No. 110796-2F, the appropriate shop fabrication drawing was No. 1107017357 Rev. 4 for spool piece No. SIS-17-1 and the welding boss sketch was No. SK-102 Rev.3. In addition, the staff reviewed the approach and attributes used in determining the SIF at branch and run intersections and indicated concerns regarding the applicability of certain attributes as used in the design criteria document 2BVM-157. Subsequently, the applicant submitted a report entitled "Stress Intensification Factors for Run Pipe Stress Evaluation at the Location of Small Branch Connections" (Draft), 10038-12241-34, dated January 1987. The report discusses: (1) the applicable requirements of the Beaver Valley Unit 2 code of record for piping design relevant to the SIF for branch connections, (2) the controlling piping components in stress calculations, (3) recent industry studies on SIF values for small branches connected to run piping, (4) industry experience with branch connection failures, and (5) the results of a SWEC review of all branch connections in the Beaver Valley Unit 2 residual heat removal (RHR) system. On

January 30, 1987, the applicant and representatives of SWEC met with the staff to discuss the report. On the basis of its review of the report, the staff concludes that the lack of appropriate fatigue data for small branches connected to run pipe does not support the use of a 1.0 SIF for run pipe evaluation at locations of small branch connections at this time. However, the general observation that straight pipe components to which small branch lines are attached are not typically the controlling stress points in ASME Class 2 and 3 piping systems, when viewed in conjunction with the fact that actual calculated stresses using an SIF of 2.1 have been demonstrated to be low at all locations of small branch connections in the RHR system provides the staff with sufficient confidence for concluding that the design of the small branch connections nonetheless is in compliance with the ASME Code. The staff's conclusion is further supported by the results of the Shoreham Independent Design Verification Program (IDVP) performed by Teledyne Engineering Services which focused on this same issue. More than 500 branch connections were reviewed at the Shoreham Nuclear Power Station, and the same conclusion, that the design is in compliance because of the low stresses, was reached. On the basis of the staff's review of the applicant's report and the consistency of the Beaver Valley Unit 2 results with those of Shoreham, this issue is closed.

Mechanical Systems Design. Action Item P-01 identified inconsistencies between the Westinghouse flow diagram and SWEC's prepared flow diagram for the nitrogen system. The applicant stated that the Westinghouse valve positions were used as input to the plant operating manuals prepared jointly by SWEC and the applicant, and therefore the positions of the Westinghouse valves no longer have design significance. Furthermore, the applicant revised project procedure 2BVM-12 to state that the operating manuals are the source of valve positions for the SWEC flow diagrams, with valves shown in their normal position for plant operations. The staff reviewed the relevant drawings and the revisions to 2BVM-12 and agreed that this item satisfied the concern of Action Item P-01. The staff also noted that the differences in valve positions between the Westinghouse and SWEC diagrams were largely a matter of convention, not design differences in actual system alignment for the various operating modes. On the basis of this review, this item is closed.

Action Item P-12 identified a number of discrepancies in the transmission of input data to stress data packages SI-RM-87A-2 and SI-RM-85A-3. The applicant explained some of the concerns and changed or corrected others. After further review and consideration of this matter, the EA team determined that the project had an adequate procedural method to ensure that the latest information is used in the initial stress analysis and to ensure that it is periodically updated before final ASME III stress reconciliation. This commitment, along with the final stress reconciliation effort, ensures the adequacy of the final stress packages.

The staff reviewed the documentation associated with this AI, including project procedure 2BVS-939 entitled "Input for Pipe Stress Analysis." As a result of this review, the staff concurs with the EA conclusion that the Power Division/Engineering Mechanics Division interface associated with stress data packages is being satisfactorily administered. This item is closed.

Action Item P-13 involved pressures and temperatures for the modes of operation for stress data package SI-RM-87A-2. This problem is related to the transfer of interface information for systems designed by Westinghouse. Specifically, the problem can occur when inappropriate reference material is used in revisions of stress input data packages. To address this problem, the applicant committed to review all six Westinghouse system stress input data packages and to upgrade the level of detail in the identification of input reference material. By letter dated May 15, 1987, the applicant stated that it has reviewed and upgraded all six Westinghouse system stress input data packages. This item is considered resolved.

Action Item P-15 involved a change in design temperature of certain instrument root-line tubing from 265°F to 275°F, which had not been reflected in design calculations. In response, the applicant established a program to confirm input to instrument tubing calculations; the applicant plans to complete the program in the first quarter of 1987. The staff determined that the confirmation program would adequately resolve the concern. The staff subsequently reviewed a followup audit performed by the EA team. The results of the audit indicated that the confirmation program is being adequately implemented. In a letter dated May 15, 1987, the applicant confirmed that any changes to temperatures and pressures would be reconciled with the associated QA Category I calculations before fuel load. This item is considered resolved.

The remaining AIs in the mechanical discipline are not individually discussed because (1) they are of lesser technical significance and (2) they have been satisfactorily resolved or corrected.

Electrical Discipline

In the electrical power discipline, 33 AIs were identified; another 45 items were identified in the instrumentation and controls area. The following staff comments are provided relative to these AIs.

Instrumentation and Controls. Action Items C-12 and C-23 resulted when two instrument setpoint calculations (RSS*8-0-C and RSS*10-0-C) were reviewed. Corrective and preventive actions were initiated to resolve the individual concerns. Nevertheless, the EA team concluded that additional setpoint calculations should be reviewed and evaluated to determine if the errors identified were random errors or if there had been a pervasive breakdown in this area. The EA team subsequently performed a supplementary audit of the QA Category I setpoint calculations, as indicated in "Corrective Action Audit of Control Systems Set Point Verification Calculations--Beaver Valley Unit 2 Project, November 3-14, 1986," which had been prepared or revised after the corrective and preventive measures were implemented for Audit No. 52. On the basis of this report, the staff concluded that the corrective and preventive measures implemented by the applicant were effective. This matter is closed.

Action Item C-17 involved the connection of Swagelok elbows and 1/8-inch soft copper tubing (neither specified nor shown on installation drawing) to the vent ports of certain three-way solenoid-operated valves (SOVs). The applicant inspected installed SOVs to determine the extent of the condition; those SOVs with the unauthorized elbows and tubing have been identified. A nonconformance and disposition (N&D) report was prepared and the elbows and vent tubes were removed; the "Instrumentation Installation Inspection Plan" (IP7.2.9) was revised to prevent such modification in the future. Information provided in the

Phase II report documents that all unauthorized attachments have been removed. Consequently, this item is closed.

Action Item C-40 stated that the RSS pumps' minimum flow recirculation valves (2RSS*MOV 154 C and D) may continuously cycle between open and shut under certain plant operating conditions, since the setpoint and re-setpoint overlap, as pointed out in calculation RSS*10-0-C. SWEC forwarded to the staff calculation RSS* 10-3-C, Rev. 3 (dated October 20, 1986) which concluded that the control function was acceptable. The staff reviewed this calculation and found it to be conservative and acceptable. Specifically, the calculation demonstrates that the limits of error (540 gpm plus 50 gpm drift) are within the allowed ± 700 gpm of setpoint (as required by process engineering). Equipment normally settles in after being placed in operation and will either stabilize completely or will develop slow and stable rates of degradation. Since the calculation verifies that the accuracy of degradation is within prescribed limits, it is unlikely that instrument loop accuracy will change after being put into service to such an extent as to cause the recirculation valves to change state. Therefore, this item is closed.

Electrical Power. Action Item E-03 identified a situation in which an unqualified limit switch, mounted on the stem of motor-operated valves 2 SIS*MOV 865 A, B, and C, would be submerged during a LOCA. This could produce a short circuit in the switch which would in turn lead to both indicator lights going on or both not lit. In response to this item, the applicant indicated that the affected Class 1E circuits are isolated by series breakers which would ensure isolation in case of flooding and that the valve indicator lights (transition status) do not have a protective function related to LOCA. In addition, the applicant has revised the FSAR to identify equipment that could be submerged during a LOCA. A change to the FSAR represents a change of a licensing commitment which will be resolved between the applicant and the staff as a part of the normal licensing process. For the purposes of design verification, this item is closed.

Action Item E-04 involved power cables delivered before May 1984 which do not meet the requirements of FSAR Section 8.3.3. This section of the FSAR addresses the flame testing requirements of Regulatory Guide (RG) 1.131 which supplement the requirements of IEEE Standard 383-1974. During the FSAR revision process, exception to these requirements for the subject cables was not taken. As a result, the applicant has issued Licensing Change Notice 1615, dated October 20, 1986, clarifying the actual extent of compliance with RG 1.131. The FSAR change has to be resolved between the staff and the applicant as a part of the normal licensing process. For the purpose of the design verification, this item is closed.

Action Item E-09 stated that the separation distance between penetrations 2RCP*21E(W), 2RCP*20E(0), and 2RCP*20D(R), did not meet the commitments of FSAR Section 8.3.1.1.16.5. Similarly, penetrations 2RCP*06B(B), 2RCP*06A(W), 2RCP*05B(P), and 2RCP*5A(W) also violate the same separation requirements. The applicant indicated that a mistake was made when channel and train assignments of the penetrations were changed. However, the revised separation distances do not violate the requirements of RG 1.75 and the staff has prepared and reviewed a licensing change notice to revise the FSAR. An FSAR change represents a change of the licensing commitment which will be resolved between the applicant and

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the staff as part of the licensing process. For the purposes of design verification, this item is closed.

Action Item E-19 concerns lack of provisions in the "Specification for Electrical Installation", 2BVS-931, Appendix M to prevent train separation violations of "C" train cables. "C" train cables are those whose power source may be either from "A" or "B" trains. Thus, if the power source for a "C" train cable is not considered during routing, "A" and "B" train source cables may be routed in the same tray. The applicant reviewed the installation design of "C" train cables and concluded that train separation requirements had been maintained. In addition, Appendix M of 2BVS-931 was revised to include clarification and consistency requirements for proper routing of "C" train cables. The staff has reviewed and finds adequate the documentation that substantiates proper train separation practices. This item is closed.

Action Item E-27 identified the use of an incorrect load in battery sizing. Specifically, calculation 12241-E-37, referenced the running current for the diesel generator fuel oil pump instead of the starting current. As a result, the Class 1E station batteries may have been undersized. The applicant has revised the battery sizing calculation utilizing the correct starting current. This revision to the calculation indicates that the battery size is unaffected. The staff finds this acceptable. This item is closed.

Action Item E-28 addressed the use of an assumed value of receiving-end power factor (PF) of 0.6 for panels PNL*ACZ-E-2, PNL*ACZ-E-3, and PNL*VI7BS2-2A in the voltage drop calculations. The applicant reviewed the power requirements of individual loads for these panels which showed that an average PF equal to or greater than 0.8 was used. Therefore, the staff concluded that the use of an assumed PF of 0.6 is conservative. The staff finds the corroborating documentation acceptable. This matter is closed.

Action Item E-29 identified a concern that, without limiting the equalizing voltage to 2.33 V/cell for charging Class 1E batteries, the dc equipment connected to the batteries may be subjected to a higher voltage than it was qualified for. FSAR Section 8.3.2 indicates that the equalizing charge for BAT*2-2 is limited to 2.33 V/cell which is equivalent to 140 V; however, Specification 2BVS-342 for BAT*CHG2-2 indicates an equalizing charge capability of 2.25 to 2.40 V/cell which is equivalent to 135 to 144 V. In response to this concern, SWEC indicated that, although the charge specification indicated a voltage range equivalent to 135 to 144 V, Chapter 39 of the Beaver Valley Unit 2 operating manual restricted the equalizing charge setpoint to 140 V maximum which is consistent with the FSAR. The NRC team reviewed the operating manual and agreed with the applicant. This item is closed.

The remaining AIs in the electrical discipline are not discussed individually, because they are generally of lesser technical significance and have been satisfactorily resolved.

Hazards Analysis

The SWEC In-Depth Technical Audit (Audit No. 50) of Beaver Valley Unit 2, performed from November 1985 to January 1986, covered the project's Hazards Analysis Program in its entirety. The staff inspected the results of Audit No. 50 on

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July 28-30, 1986. In the report of this inspection (Inspection Report 50-412/86-23), the staff concluded:

> The Hazards Analysis Program Audit (SWEC EA Audit No. 50) was performed in sufficient technical depth and scope to provide an evaluation of the design in the hazards protection area. Other than follow-up of corrective action from EA Audit No. 50, and review of specific items which have been carried over for completion into Audit No. 52 (namely the safe-shutdown analyses associated with high-energy-line break, internally generated missile protection, and seismic/nonseismic interactions), no further design review is necessary in this area.

Section 6.3.4.2 of Audit No. 52 addressed the Hazards Analysis Program review performed to supplement the Audit No. 50 work. Supplementary review was necessary because some portions of the project's program had not been fully implemented at the time Audit No. 50 was performed. Specifically, the safe-shutdown analysis associated with high-energy-line break, protection from internally generated missiles, and analysis of seismically induced interactions between safety-related and non-safety-related structures and components had not been fully implemented. As a result of Audit No. 52, the EA team concluded that implementation of procedures in all three of the above areas was progressing satisfactorily and that the programs for internally generated missiles and seismically induced safety/non-safety interactions were continuing. The staff reviewed documentation supporting the conclusions of the EA team in Audit No. 52 and concurs with the EA team's report that these programs are comprehensive and well documented and that the implementation documents reviewed provide confidence that the completed programs will adequately address hazards concerns. The staff also reviewed two FSAR change requests necessary to support the hazards program at Beaver Valley Unit 2 and concurs that these changes (No. 1536 [postulated piping failures] and No. 1571 [NUREG/CR-2913]) adequately address concerns raised in the audits.

Action Item E-16 resulted from an EA team field walkdown which identified chain-hung lighting fixtures in close proximity to seismic Category I equipment. The generic calculation (NM(B)-34-CZ) which purportedly contained the seismic qualification of the lighting fixtures and a calculation of the maximum possible deflection, apparently did not address the particular configuration identified. In addition, hazards procedures 2BVM-165 did not address the deflection space envelope required for safety-related components adjacent to chain-hung lighting fixtures. In order to resolve these items, calculation NM(B)-34-CZ was revised to include the seismic qualification of the lighting fixture in question and procedure 2BVM-165 was revised to include space envelope requirements for chain-hung lighting fixtures. The staff has reviewed the revised seismic qualification calculation (NM(B)-34-CZ) as well as the revision to 2BVM-165 and concurs that the changes adequately address the concerns raised. This item is closed.

The applicant, in a letter dated May 15, 1987, indicated that the internally generated missile activities and seismically induced safety/non-safety interaction assessments have been fully implemented. The hazards review is considered closed.

Structural Discipline

Sixteen AIs were identified in Audit No. 52 in the structural area, and another 18 were identified in Audit No. 44. The following staff comments are provided relative to these action items.

Item 1.3 of EA Audit No. 44 covered the inconsistency between FSAR and SRP Sections 3.8.4. FSAR Section 3.8.4 applies to seismic Category I concrete structures outside of containment, including the fuel building. Although FSAR Section 3.8.4 does not include load combinations containing thermal effects and loads due to normal operating or shutdown conditions (T_o) and pipe reactions due to normal operating or shutdown conditions (R_o), Structural Design Criterion 2BVM-5 does require these load combinations for the fuel building design. Calculation C38 follows the Structural Design Criteria and includes the appropriate load combination. Licensing Change Notice No. 1638 has been prepared which revises Section 3.8.4 of the FSAR to include load combinations which consider T_o and R_o. This FSAR change constitutes a change to a licensing commitment that will be resolved between the applicant and the staff as part of the normal licensing process. However, for the purpose of the design verification, this item is closed.

Item 2.4 of EA Audit No. 44 concerns the moment distribution methods and end-condition assumption of a beam at the 752-foot and 3-inch elevation in the fuel building. The beam extends from the north wall to the south wall and has an intermediate support. The north wall contains a pilaster; the south wall does not. The original designer took the north end to be fixed and the south end to be pinned. The auditor noted that there were errors in the moment distribution method and judged that the south end of the beam should also be considered fixed. A revised calculation was performed during this audit which justified that the beam was adequately reinforced for the true condition. The staff has reviewed the revised calculation and concurs that the beam is adequately reinforced. Therefore, this item is closed.

During the staff's review of substantiating calculations for EA Audit No. 44, several omissions and inconsistencies were observed. SWEC has agreed to address these concerns as part of the confirmatory thermal analysis calculations for the fuel building. They are:

(1) The normal operating temperature of the fuel building is 90°F for winter and 70°F for summer. Since the temperature would normally be expected to be hotter during summer than winter, this input was questioned.

(2) The accident temperatures used in calculation C38.13.1-6 do not correspond to Structural Design Criteria and are apparently based on interoffice correspondence. The finite element analysis of the fuel pool was also performed using temperatures from calculation C38.13.1-6.

The staff has reviewed corroborating documentation submitted by the applicant which indicates that the temperature variations have been correctly determined and that supplementary calculations have been completed which conform to the requirements of the Beaver Valley Unit 2 Structural Design Criteria. This item is closed.

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Action Item S-10 concerned the calculation of vertical seismic effects for cable tray support systems. The mass of filled cable trays and supports were lumped on the vertical member instead of at the midspan of the cable trays and horizontal members of the trapeze. The omitted stiffnesses of the cable trays and horizontal members could result in overestimated natural frequencies. The applicant responded by demonstrating that the missing stiffness effects would not result in frequency shifts which would significantly increase the seismic loading. In addition, two conservatisms are inherent in cable tray support designs, namely:

(1) The actual cable tray support spans are generally less than 8 feet; which is the design maximum.

(2) The actual cable weight is generally less than the design cable fill weight.

The staff has reviewed the corroborating documentation and agrees with the conclusions of the EA team. This item is closed.

Action Item S-12 deals with the design of structural steel and specifically concerns the omission of load combination,

$$1.5S = D + L + OBE + T_o + R_o$$

and the assumptions that the effects of normal operating temperature variations on the structural steel were negligible and that equipment and piping loads could be accounted for by using 50% of the live load as an allowance. The applicant responded by incorporating the missing load combination into the Structural Design Criteria (2BVM-5) and developed additional corroborating calculations to demonstrate that the assumptions made regarding operating temperature variations and piping and equipment load allowances for structural steel are indeed valid. The staff has reviewed the corroborating documents and determined that the scope of this item has been adequately addressed; therefore, this item is closed.

Action Item S-14 concerned the omission of the consideration of longitudinal warping stresses in the design of structural steel beams for twisting moments. The applicant responded by indicating that this was an isolated case and because the calculation was not final, the omission would have been detected as part of the Structural Confirmation Program (2BVM-168). The staff has reviewed the corroborating documentation and agrees. This item is closed.

The remaining AIs in the structural discipline are not discussed individually because they are generally of lesser technical significance and have been satisfactorily resolved.

17.5.5 Trend Analysis

In the Phase II report, the EA team discusses a number of concerns or trends indicated from the Phase II evaluation. The Phase II report states that the corrective and preventive action taken as a result of individual audits resolved concerns and alleviated trends. NRC staff comments on the more significant of these potential trends are provided below.

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Calculations

The staff noted that approximately one-third of all valid findings related to calculations. This is not unusual, since a large number of calculations were reviewed during the various audits. In addition, most of the AIs were miscellaneous deficiencies, lack of adequate justification of engineering judgments, or incorrect design input and/or assumptions, as opposed to technical concerns which would be of greater overall concern.

Nevertheless, to address a concern expressed by the NRC staff, that the nature of the deficiencies associated with the setpoint calculations in the instrumentation and control discipline might indicate a breakdown in the design process in this area, a supplemental audit was performed on a large sample of calculations prepared subsequent to Audit No. 52. As a result of this effort, the staff concluded that the corrective and preventive actions implemented on the basis of Audit No. 52 adequately addressed the staff's concerns.

In addition, the applicant has instituted extensive confirmation and reconciliation programs such as 2BVM-117, "Confirmation Program to Key Documents" and 2BVM-122, "Engineering Confirmation Update Program" to identify and correct the types of deficiencies noted during the engineering assurance audit program. This should increase the overall quality of calculations. The staff concludes that adequate control of the calculation process exists at Beaver Valley Unit 2.

FSAR Inconsistencies

Inconsistencies between the FSAR and other design documents were noted in several EA audits of Beaver Valley Unit 2 and accounted for approximately 15% of the findings. Some discrepancies involved incorrectly or unclearly written text. Most discrepancies reflected a failure to revise the FSAR and were generally editorial in nature, and carried no design impact. As a result of earlier findings, steps were taken to improve the consistency between the design documents and the FSAR. In addition, guidance has been provided to require that the potential effects on licensing documents is carefully considered when design changes are prepared. In view of the improvements in FSAR control resulting from the continuing EA audits, the staff considers FSAR control to be adequate and no additional action is required.

Design Interface

In some design areas, specific omissions were found in design interface. Although most of the findings were limited to isolated occurrences, there were three power discipline interface concerns that resulted in plant operating restrictions. As a result of these findings, additional reviews of power discipline calculations and the plant operating manual were performed to assess the overall implications of the original findings. It was concluded that these findings would have been detected as a result of the ongoing design process, including the Beaver Valley Unit 2 Confirmation Programs. The staff concludes that design interface control on the project is adequate and no additional action is required.

17.5.6 NRC Staff Conclusions

The applicant engaged SWEC's Engineering Assurance Division to conduct an in-depth technical audit of the design activities at Beaver Valley Unit 2. This

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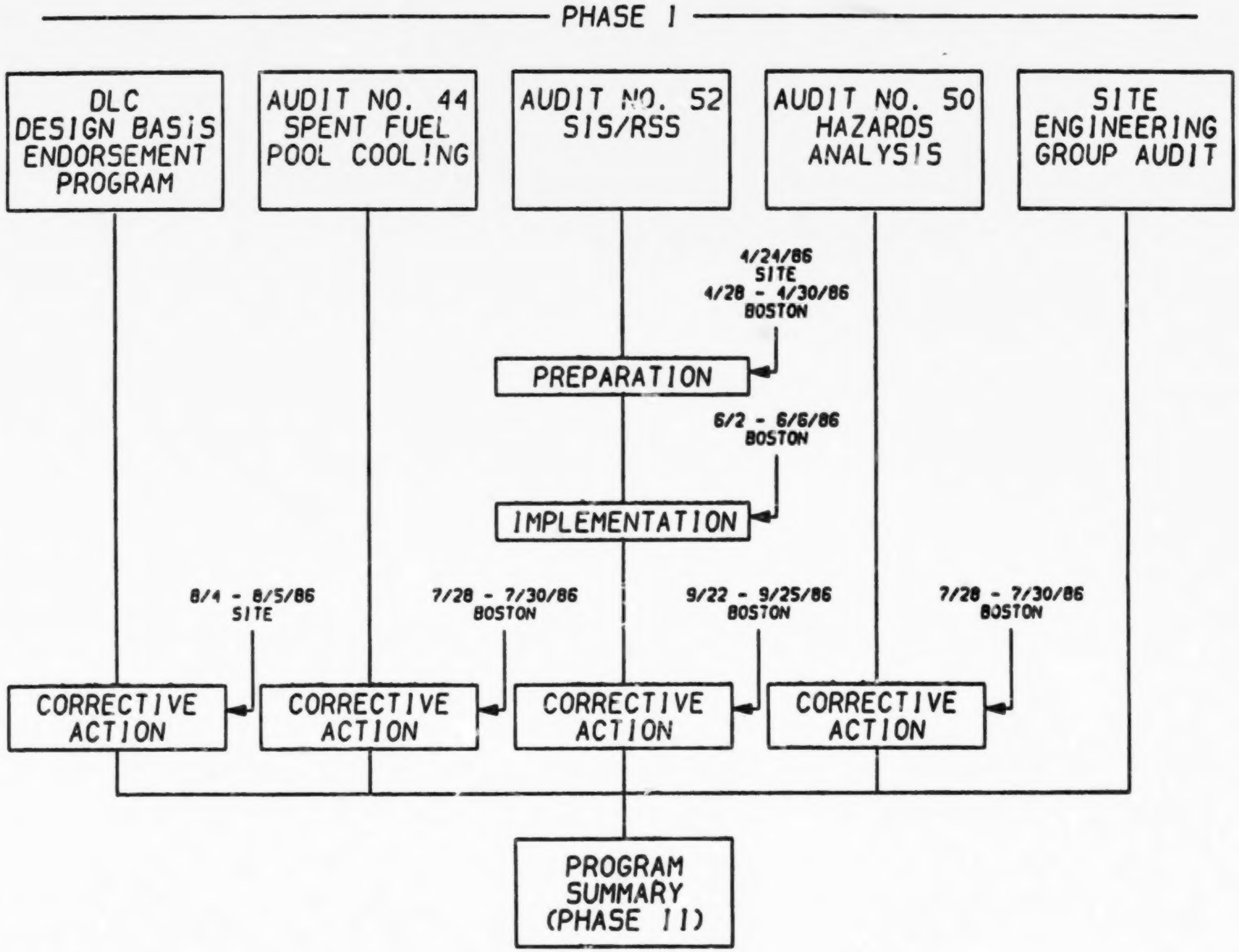
audit, along with an analysis of it and previous audits relative to the effectiveness of design process implementation, was accepted by the staff as a method for providing additional assurance that the design of Beaver Valley Unit 2 complies with all licensing commitments and regulatory requirements. The audit and subsequent analysis of several audits involved a substantial effort which evaluated numerous documents. The staff closely monitored the audit and evaluations at all stages of activity, including monitoring of corrective actions. In view of the monitoring performed by the staff as detailed in this SER supplement, the staff concludes that the Engineering Assurance Program audits provide significant additional confidence that the design of Beaver Valley Unit 2 is in accordance with design commitments and regulatory requirements.


PHASE I
DLC DESIGN BASIS ENDORSEMENT PROGRAM
AUDIT NO. 44 SPENT FUEL POOL COOLING
AUDIT NO. 52 SIS/RSS
AUDIT NO. 50 HAZARDS ANALYSIS
SITE ENGINEERING GROUP AUDIT
4/24/86 SITE
4/28 - 4/30/86 BOSTON
PREPARATION
6/2 - 6/6/86 BOSTON
IMPLEMENTATION
8/4 - 8/5/86 SITE
7/28 - 7/30/86 BOSTON
9/22 - 9/25/86 BOSTON
7/28 - 7/30/86 BOSTON
CORRECTIVE ACTION
CORRECTIVE ACTION
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PROGRAM SUMMARY (PHASE II)

Figure 17.1 Beaver Valley Unit 2 Engineering Assurance Program

18 HUMAN FACTORS ENGINEERING

18.1 Detailed Control Room Design Review

In SSER 1, the staff stated that a site audit was performed on February 11 and 12, 1986. The staff further stated that the applicant was conducting a detailed control room design review (DCRDR) that would generally meet the requirements of Supplement 1 to NUREG-0737, but that a supplemental summary report would be required from the applicant to close open issue 10.

As a result of the audit, the staff issued an interim safety evaluation report on the DCRDR on July 28, 1986 (P. Tam to J. Carey). The organization, process, and results to date of the Beaver Valley Unit 2 DCRDR were compared with the requirements of Supplement 1 to NUREG-0737 and the guidelines in Section 18.1 of the Standard Review Plan. The staff concluded that the applicant has conducted a comprehensive DCRDR and has generally satisfied the requirements of Supplement 1 to NUREG-0737. The applicant needs to complete certain items and to report their completion in a supplemental summary report.

In response to the staff's July 28, 1986 document, the applicant submitted the "DCRDR Supplemental Summary Report" (SSR) on January 8, 1987. In addition, by letter dated April 3, 1987, the applicant committed to complete all DCRDR surveys, satisfactorily resolve all open DCRDR issues, and implement all proposed control room changes resulting from the DCRDR, before startup following the first refueling outage.

On the basis of the completion of the bulk of work on the DCRDR, and the applicant's commitment, the staff considers open issue 10 closed. Remaining actions, including response to the staff's detailed review of the SSR and implementation of needed improvements, will be tracked by licensing action TAC 62879, and will be reported in a future document.

18.2 Safety Parameter Display System

In the SER, the staff stated that additional information regarding the safety parameter display system (SPDS) will be needed and onsite audits will be performed by the staff. By letters dated December 20, 1985; April 9, 1986; and June 16, 1986, the applicant provided additional information as requested by the staff. The staff onsite design verification and design validation audit took place February 17-18, 1987.

As a result of this audit, the staff concludes that no serious safety questions are posed by the proposed SPDS, and therefore, implementation of the Beaver Valley Unit 2 SPDS may continue. This conclusion does not imply that the SPDS meets or will meet requirements of Supplement 1 to NUREG-0737. Such confirmation can be made only after a postimplementation audit, and after the staff has evaluated the applicant's response to the detailed conclusions and recommendations to be reported in a forthcoming technical evaluation report of the audit.

By letter dated April 3, 1987, the applicant committed to provide acceptable responses and implement corrective actions related to the SPDS. An appropriate implementation schedule will be developed by the NRC project manager via discussions with the applicant. The applicant is required to inform the Commission, in writing, about any significant changes in the estimated completion schedule and to tell the staff when the action has been completed.

On the basis of the commitment to resolve issues and implement corrective actions, and completion of the bulk of the review, the staff considers open issue 11 closed. Remaining actions, including response to the staff's technical evaluation and implementation of needed corrective actions, will be tracked by licensing action TAC 62880 and will be reported in a future document.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF NRC STAFF RADIOLOGICAL REVIEW OF BEAVER VALLEY POWER STATION, UNIT 2

January 30, 1987	Meeting with applicant to discuss stress intensification factor (summary dated February 24, 1987).
February 2, 1987	Letter from applicant requesting exemptions from GDC 4 based on WHIPJET Program. Letter also transmitted information requested by the staff on WHIPJET in the January 16, 1987 meeting.
February 2, 1987	Letter to applicant approving use of ASME Code Case N-253-1.
February 3, 1987	Letter to applicant transmitting summary of meeting on January 5 1987, at Region 1, subject was Unit 1/2 operator cross-training.
February 4, 1987	Letter from applicant certifying FSAR Amendment No. 14 has been distributed.
February 11, 1987	Letter from applicant providing additional information on Supplemental DCRDR Summary Report.
February 11, 1987	Letter to applicant requesting submittal of detailed information on TMI Issue II.D.1, safety/relief valves.
February 11, 1987	Letter from applicant transmitting additional information in response to the staff's site visit of January 26-30, 1987 regarding fire protection.
February 11, 1987	Letter to applicant requesting information on plant safety monitoring system verification and validation.
February 11, 1987	Letter from applicant certifying all conditions in Material License SNM-1954 have been met and implemented.
February 11, 1987	Letter from applicant transmitting additional information on control room design review.
February 11-12, 1987	Meeting with applicant on inservice testing, open issue 1(b). Meeting summary dated March 11, 1987.
February 11, 1987	Letter from applicant commenting on "Proof and Review" version of the Technical Specification.

February 13, 1987	Letter from applicant transmitting additional information on the WHIPJET program.
February 13, 1987	Letter from applicant providing information on the combined station security system.
February 19, 1987	Letter from applicant providing Physical Security Plan and implementation schedule.
February 19, 1987	Letter to applicant transmitting staff position on steam generator high-level trip.
February 17-19, 1987	Onsite audit of safety parameter display system, open issue 11.
February 20, 1987	Letter to applicant transmitting staff position on steam generator high level trip.
February 23, 1987	Letter from applicant providing additional information on Engineering Assurance Program.
February 24, 1987	Meeting with applicant on safe shutdown. Summary dated March 11, 1987.
February 24, 1987	Letter to applicant stating staff position on 10 CFR 50 Appendix I (Annex (RM 50-2)
February 24-27, 1987	Meeting with applicant on preparation of technical specifications.
February 27, 1987	Letter from applicant transmitting information on ATWS mitigation system actuation circuitry.
February 27, 1987	Letter to applicant requesting additional information on confirmatory issue 32, control system failure.
March 2, 1987	Letter to applicant requesting additional information on Generic Letter 83-28 item 2.2.1.
March 2, 1987	Letter from applicant transmitting Amendment No. 15 to the FSAR.
March 4, 1987	Letter from applicant certifying distribution of FSAR Amendment No. 15.
March 4, 1987	Letter from applicant providing additional comments on the SER.
March 4, 1987	Letter from applicant requesting schedular exemption from 10 CFR 50.55a(h) regarding steam generator high level trip.

March 4, 1987	Letter from applicant transmitting additional information to concerns raised in November 18-20, 1986 equipment qualification audit.
March 5, 1987	Request for additional information on confirmatory issue 14, equipment qualification.
March 5, 1987	Letter from applicant requesting schedular exemptions from the Annex (RM 50-2) to 10 CFR 50 Appendix I.
March 5, 1987	Letter from applicant providing additional information on fire protection.
March 6, 1987	Letter from applicant requesting technical exemption from 10 CFR 50, Appendix J, concerning containment airlock testing.
March 6, 1987	Letter from applicant transmitting revised proposed technical specifications on pressure isolation valves.
March 9, 1987	Letter from applicant stating that design for control room isolation on high radiation is complete.
March 9, 1987	Letter from applicant providing remaining information on confirmatory issue 2, differential pipe settlement.
March 10, 1987	Letter from applicant providing status of confirmatory issues.
March 11, 1987	Letter to applicant transmitting interim review results on confirmatory issue 50, initial test program.
March 12, 1987	Letter to applicant transmitting preliminary draft of low-power operating license.
March 12, 1987	Letter from applicant requesting authorization to use ASME Code Case 1481-2.
March 12, 1987	Letter from applicant addressing relief requests related to preservice inspection of welds (open issue 4(a)).
March 12, 1987	Letter from applicant addressing Safety-Related Instrument Tubing Program.
March 13, 1987	Letter to applicant providing a copy of environment assessment on the exemption from GDC 4.
March 20, 1987	Letter to applicant transmitting 20 copies of SER Supplement No. 4.
March 20, 1987	Letter to applicant regarding offsite medical services for emergency preparedness.

March 23, 1987	Letter from applicant informing of changed fuel load date to May 21, 1987, due to replacement of main steam isolation valves.
March 23, 1987	Letter from applicant revising the Physical Security Plan.
March 24, 1987	Site visit by the ACRS Metal Components Subcommittee to inspect pipes in the WHIPJET program.
March 24, 1987	Letter from applicant providing notification of submittal of Fire Protection Safe Shutdown Report under separate cover.
March 24, 1987	Letter from applicant transmitting additional information on equipment qualification, confirmatory issue 14.
March 26, 1987	ACRS Metal Components Subcommittee meeting to address application of leak-before-break technology (WHIPJET).
March 26, 1987	Letter from applicant providing additional information on equipment qualification, confirmatory issue 14.
March 26, 1987	Letter from applicant transmitting Issue 9, Revision 0 of the Emergency Preparedness Plan and procedures.
March 30, 1987	Letter to applicant requesting additional information on confirmatory issue 21, MULTIFLEX.
March 31, 1987	Letter from applicant providing Amendment 5 of Failure Modes and Effects Analysis report.
April 1, 1987	Letter to applicant transmitting Amendment 2 to Material License SNM-1954.
April 1, 1987	Letter from applicant transmitting Amendment No. 16 to the FSAR.
April 1, 1987	Letter from applicant addressing confirmatory issue 41(d), procedures for reporting ECCS outage.
April 1, 1987	Meeting with applicant to address SQRT and PVORT issues (summary dated April 8, 1987).
April 2, 1987	Letter from applicant responding to the staff's letter of March 20, 1987 on offsite medical services.
April 2, 1987	Letter from applicant providing status of outstanding SER issues.
April 3, 1987	Letter from applicant providing latest revision to Chapter 17 of the PSAR, quality assurance.
April 3, 1987	Letter from applicant to certify distribution of Amendment No. 16 to the FSAR.

April 3, 1987	Letter from applicant providing commitment to resolve issues related to safety parameter display system (open issue 11).
April 3, 1987	Letter from applicant providing commitment to resolve issues related to detailed control room design review (open issue 10).
April 3, 1987	Letter from applicant requesting relief from certain preservice inspection (PSI) requirements.
April 6, 1987	Letter from applicant transmitting proposed changes to FSAR Chapter 14.
April 7, 1987	Letter from applicant providing additional information on confirmatory issue 32, control system failure.
April 8, 1987	Letter to applicant requesting confirmation of certain items in the Engineering Assurance Program.
April 8, 1987	Letter from applicant submitting the ASME Code Baseline Document, Revision 4.
April 8, 1987	Letter from applicant submitting Procedure Generation Package for emergency procedures (confirmatory issue 47).
April 10, 1987	Letter to applicant transmitting final draft of the Technical Specifications.
April 10, 1987	Letter from applicant providing information for confirmatory issue 11, safety/relief valves.
April 13, 1987	Letter from applicant commenting on the draft operating license dated March 12, 1987.
April 13, 1987	Letter from applicant confirming establishment of Diesel Generator Training Program (confirmatory issue 37).
April 13, 1987	Letter from applicant documenting telephone conference with the staff on application of construction visual examination results for Safety Class 3 supports.
April 13, 1987	Letter from applicant transmitting Core Damage Assessment Procedure (confirmatory issue 36).
April 13, 1987	Letter from applicant transmitting information on confirmatory issue 25, containment sump blockage.
April 13, 1987	Letter from applicant transmitting drawings related to bottled air system and control room ventilation system.
April 13, 1987	Letter from applicant requesting a change to Material License SNM-1954.

April 15, 1987	Letter from applicant providing revised pages to Physical Security Plan.
April 15, 1987	Letter from applicant transmitting revised Inservice Testing (IST) Program, as a result of the meeting on February 11 and 12, 1987.
April 16, 1987	Letter from applicant providing responses to questions raised by the SQRT and PVORT (confirmatory issues 12 and 13).
April 22, 1987	Letter from applicant responding to the staff's request for information on MULTIFLEX (confirmatory issue 21).
April 22, 1987	Letter from applicant responding to the staff's request for information on reactor coolant pump trip criteria (confirmatory issue 41 (c)).
April 24, 1987	Letter to applicant informing of results of antitrust review.
April 24, 1987	Letter from applicant transmitting additional information on ATWS mitigation system actuation circuitry.
April 24, 1987	Letter from applicant providing results of onsite ac power system voltage analysis.
April 24, 1987	Letter from applicant providing additional information to finalize the Technical Specifications.
April 24, 1987	Letter from applicant informing staff of completion of shunt coil trip attachment installation (confirmatory issue 26).
April 24, 1987	Letter from applicant transmitting turbine missile probability analysis (confirmatory issue 5).
April 27, 1987	Letter to applicant transmitting draft environmental plan (Appendix B to the operating license).
April 29, 1987	Letter from applicant addressing confirmatory issue 41(a), reactor coolant leakage outside containment.
April 29, 1987	Letter from applicant providing information requested by the PVORT.
April 30, 1987	Letter to applicant transmitting environmental assessment for two proposed exemptions.
April 30, 1987	Letter to applicant transmitting request for additional information on confirmatory issues 48 (fire protection) and 46 (control room isolation).

May 1, 1987	Letter from applicant transmitting Amendment 17 to the FSAR.
May 7, 1987	Letter to applicant rescinding previous staff positions on use of the Annex to Appendix I, 10 CFR 50.
May 7, 1987	Letter from applicant providing additional information for the Technical Specifications.
May 7, 1987	Letter from applicant responding to the staff's questions on several Salem ATWS event issues.
May 11, 1987	Letter from applicant providing additional information on safe and alternate shutdown (open issue 5).
May 11, 1987	Letter from applicant providing additional information on the SQRT and PVORT reviews (confirmatory issues 12 and 13).
May 11, 1987	Letter from applicant transmitting Westinghouse report WCAP-11461 on Beaver Valley Unit 2 natural circulation analysis.
May 11, 1987	Letter from applicant providing current status of open and confirmatory issues.
May 11, 1987	Letter from applicant addressing the staff concern regarding the Offsite Dose Calculation Manual.
May 12, 1987	Two letters from applicant providing additional information on initial tests (confirmatory issue 52).
May 12, 1987	Letter from applicant stating that the inadequate core cooling instrumentation has been installed.
May 13, 1987	Letter from applicant stating that the bypass and inoperative of status panel has been installed.
May 14, 1987	Letter to applicant providing chronology of approved safeguards plan.
May 15, 1987	Letter to applicant providing draft of "change" pages in Amendment 18 to the FSAR.
May 15, 1987	Letter from applicant stating the completion status of dynamic qualifications of safety-related equipment.
May 15, 1987	Letter from applicant providing status of completion of the Engineering Assurance Program.
May 15, 1987	Letter from applicant addressing an issue in the Technical Specifications.
May 18, 1987	Letter from applicant providing status of environmental qualification of safety-related equipment.

May 18, 1987	Letter from applicant providing draft of "change" pages in Amendment 18 to the FSAR.
May 19, 1987	Letter from applicant providing status of installation of the bypass and inoperative status panel.
May 19, 1987	Letter to applicant transmitting requirements on control room isolation instrumentation.
May 20, 1987	Letter from applicant transmitting additional information on fire protection (comfirmatory issue 48).
May 20, 1987	Letter from applicant providing additional information on Engineering Program.
May 22, 1987	Letter from applicant responding to staff's letter dated May 19, 1987 on control room isolation instrumentation.
May 25, 1987	Letter from applicant providing additional information on initial testing (confirmatory issue 52).
May 25, 1987	Two letters from applicant providing status of equipment qualification (confirmatory issue 14).
May 25, 1987	Letter from applicant providing completion status of construction and testing.
May 26, 1987	Letter from applicant providing additional information regarding turbine overspeed Technical Specification.
May 26, 1987	Letter from applicant committing to perform certain tests (confirmatory issue 52).
May 27, 1987	Letter to applicant transmitting revised pages to the final draft version of the Technical Specifications.
May 27, 1987	Letter from applicant to provide information on peaking factor Technical Specification.
May 27, 1987	Letter from applicant certifying the final version of the Technical Specifications.

APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

Staff Reviewer	Title
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APPENDIX H

ACRS LETTER AND STAFF RESPONSE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

March 16, 1987

Docket No. 50-412

MEMORANDUM FOR: Raymond F. Fraley, Executive Director
Advisory Committee for Reactor Safeguards (ACRS)

FROM: Lester S. Rubenstein, Director
PWR Project Directorate #2
Division of PWR Licensing-A

SUBJECT: ADDITIONAL AND UPDATED RESPONSE TO ACRS LETTER DATED NOVEMBER 13, 1985, REGARDING BEAVER VALLEY UNIT 2

By memorandum dated February 20, 1986, the staff responded to the subject ACRS letter. The memorandum addressed two of the three issues the ACRS requested the staff to follow-up. Following is an updated status of these three issues.

Steam Generator Tube Rupture (SGTR)

In its February 20, 1986, letter the staff reported that a preliminary review of the Westinghouse Owners Group (WOG) Topical Report WCAP-10698, "Steam Generator Tube Rupture Analysis Methology to Determine Margin to Steam Generator Overfill" had been performed. The WOG has since submitted a second topical report, WCAP-11002, "Evaluation of Steam Generator Overfill Due to a Steam Generator Tube Rupture Accident." The staff performed a concurrent detailed review of both topical reports and requested additional information. The responses have been received and have been reviewed by the staff.

A meeting with the WOG SGTR Subgroup was held on January 14, 1987. The staff indicated that while the thermal and hydraulic (T&H) and systems analysis methodology was acceptable, the staff questioned the assumed operator action times, considering them too optimistic. The staff also questioned use of steam generator level as the primary indication of SGTR, including identification of the ruptured SG. The staff will meet with W to go over the SGTR Emergency Response Guidelines (ERGs) to determine the validity of the action times and primary indication assumed. In the event that the staff concludes that the operator action times are too optimistic, the staff may further conclude that SG overfill is part of the design basis SGTR scenario. In WCAP-11002, the WOG submitted an offsite dose analysis which assumes a stuck open SG safety valve (SV) as a result of liquid relief, since the SVs are only designed for steam relief. However, the analysis is based on "best estimate" assumptions. If the staff concludes that overfill is part of the design basis SGTR scenario, the staff may require use of conservative (Chapter 15) assumptions for offsite dose calculations in the event of a stuck open SV due to liquid relief. Assuming these issues can be resolved in a timely manner, the staff expects to issue a generic SER in June 1987, two months after the proposed Beaver Valley Unit 2 fuel load date.

The staff expects that, if approved, the generic analysis, enhanced by the plant-specific information requested, will meet the SGTR accident analysis requirements. The staff review may also lead to revised SGTR emergency response guides and procedures.

Alternate Pipe Rupture Protection (Application of Leak-Before-Break Criteria to Certain Stone and Webster-Supplied Piping)

As indicated in the February 20, 1986, memorandum, the staff plans to brief the ACRS on review results of this issue. A Metal Component Subcommittee meeting has been proposed for March 26, 1987. The staff has completed review of this issue and the results have been published in SER Supplement 4 (March 1987).

Decay Heat Removal System Seismic Design

The ACRS recommended that the applicant evaluate the "seismic capability of the emergency AC power supplies, DC power supplies, and small equipment such as actuators and instrument lines that are part of the decay heat removal system to assure that adequate safety margin exist." In a letter dated January 9, 1986, the applicant stated that the BVPS-2 decay heat removal system is designed as a seismic Category I system. However, the applicant did not quantitatively address the safety margins of equipment as requested by the ACRS.

For all seismic Category I systems, components, equipment and their support, the staff has reviewed their seismic qualification in accordance with Standard Review Plan sections 3.9.2 and 3.10. The qualification methods and procedures, including testing and analyses, have been evaluated to ensure design adequacy to maintain their safety function during and after earthquake events up to and including the SSE. See SER supplement 4 for the detailed report by the Seismic Qualification Review Team.

Daniel G. McDonald Jr

acting for Lester S. Rubenstein, Director
PWR Project Directorate #2
Division of PWR Licensing-A

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APPENDIX P

ERRATA

Errors in SER:

Page	Location	Comment
5-26	Third paragraph, first sentence	Should read "The contents of the tank can be drained to the degasifiers in the boron recovery system via the primary drains transfer pumps."
8-6	Second paragraph of Section 8.3.1.2, third sentence	Should read "Surveillance requirements will be included in the Technical Specifications to verify that the appropriate protective trips are bypassed."
9-14	Sixth paragraph, last two sentences	Should read "Each pump and heat exchanger is rated at 50% capacity during normal plant operation, with the service temperature at its maximum and all nuclear auxiliaries operating at maximum loads. The PCCW system, in conjunction with the residual heat removal system, is designed to reduce the temperature of the reactor coolant in the periods of time and with the pump/heat exchanger combinations given in SER Section 5.4.7."
10-3	First paragraph, fifth line (continuation of item (3)) and sixth line	"...control...valves)" should be changed to read: "control, intercept, and reheat stop valves)".
15-1	Table before last paragraph	In the column under "Parameter", the entry "Average reactor vessel temperature, °F" should be replaced by "Average reactor coolant system temperature, °F".

Errors in SSER 4:

Page	Location	Comment
3-1	Second paragraph, third sentence	Change date to "March 3, 1986."
10-1	Fourth sentence and last sentence	Change "127,000" to "127,500."

APPENDIX R

DUQUESNE LIGHT COMPANY
BEAVER VALLEY POWER STATION - UNIT 2
DOCKET NUMBER 50-412

SAFETY EVALUATION REPORT SUPPLEMENT
PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I. INTRODUCTION

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permits were issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) specifies that components (including supports) which are classified as ASME Code Class 1 and 2 must meet the preservice examination requirements set forth in the edition of Section XI of the ASME Code and addenda in effect six months prior to the date of issuance of the construction permit. The provisions of 10 CFR 50.55a(g)(2) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

Requests for relief from the ASME Code Section XI requirements which the Applicant has determined to be impractical for systems and components at Beaver Valley Power Station Unit 2 were contained in submittals dated March 12, 1987, and April 6, 1987. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing these submittals to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for Beaver Valley Power Station Unit 2 was issued on May 3, 1974. In accordance with 10 CFR 50.55a(g)(2), components (including supports) which are classified as ASME Code Class 1 and 2 have been designed and provided with access to enable the performance of required preservice examinations.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

In the case of Beaver Valley Power Station Unit 2, a large percentage of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not affect the assurance of initial structural integrity.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examinations can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of the preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric examination is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

Several of the preservice inspection relief requests involve examination of less than the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic service-induced degradation. In the event that the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

III. EVALUATION OF RELIEF REQUESTS

The Applicant requested relief from specific preservice inspection requirements in submittals dated March 12, 1987, and April 6, 1987. All of these relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Based on the information submitted by the Applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice inspections required by the ASME Boiler and Pressure Vessel Code, Section XI, have been determined to be impractical to perform. The Applicant is required to demonstrate that either (i) the proposed alternative would provide an acceptable level of quality and safety, or (ii) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1980 Edition including Addenda through Winter 1980 (80W80).

A. Relief Request, Examination Category B-B, Items B2.11 and B2.12, Pressurizer Shell-to-Head Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-B, Items B2.11 and B2.12 both require a 100% volumetric examination of circumferential and longitudinal Pressurizer Shell-to-Head welds as defined by Figures IWB-2500-1 and IWB-2500-2.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Pressurizer welds:

Pressurizer 2RCS-PRE21
(Drawing No. 2DLC-UPO-1002)

Weld No.	Percent Not Examined 0	45	60
1		6%	25%
2		<1%	<1%
4	2%	3%	4%
5		1%	1%
6	12%	12%	12%
7		8%	11%

Reason for Request: The ultrasonic volumetric examination of the above welds is restricted by interferences caused by welded pads, branch connections, pressurizer skirt, and/or valve support rings.

The Applicant reported that the Code-required volumetric examination was performed on all accessible areas of the subject welds, and that these welds all received ASME Code Section III surface examinations during fabrication.

Staff Evaluation: The staff has reviewed the Applicant's submittal, which included a listing of the welds for which relief is being requested, the weld design, the Code requirement from which relief is being requested, and the specific obstruction which limits the examination.

Based on the above review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the pressurizer would have to be redesigned in order to complete the remainder. The staff concludes that the limited Section XI volumetric examination and the Section III fabrication examination, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

B. Relief Request, Examination Category B-H, Item B8.20, Pressurizer Integrally Welded Attachments

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-H, Item B8.20 requires a 100% volumetric or surface examination, as applicable, on Pressurizer integrally welded attachments as defined by Figures IWB-2500-13, 14, and 15.

Code Relief Request: Relief is requested from performing 100% of the Code-required examination of the following Pressurizer integrally welded support skirt weld:

Pressurizer 2RCS-PRE21
(Drawing No. 2DLC-UPO-1002)

Weld No.	Volumetric Percent Not Examined 0	45	60
8	0%	20%	23%

Reason for Request: The Applicant reports that in addition to the above described volumetric examination, a surface examination was performed on the outside weld surface; however, surface examination of the weld surface under the skirt is impractical due to physical limitations imposed by the skirt design, heater penetrations, and insulation support brackets. The Applicant also reported that the subject weld received the ASME Code Section III required fabrication examinations.

Staff Evaluation: Based on review of the Applicant's submittal, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the Pressurizer support skirt would have to be redesigned in order to complete the remainder. The staff concludes that the limited Section XI surface and volumetric examinations, together with the Section III fabrication examinations, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

C. Relief Request, Examination Category B-D, Items B3.110 and B3.120, Pressurizer Nozzle-to-Vessel Welds and Nozzle Inside Radius Sections

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Items B3.110 and B3.120 require a 100% volumetric examination of Pressurizer nozzle-to-vessel welds and nozzle inside radius sections as defined by Figure IWB-2500-7.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Pressurizer nozzle-to-vessel welds and nozzle inside radius sections:

Pressurizer 2RCS-PRE21
(Drawing No. 2DLC-UPO-1002)

Weld Nos.	Nozzle-to-Vessel Welds Percent Not Examined 0	45	60
10 through 14	33%	64%	80%

Nozzle Inside Radius Percent Not Examined 0	45	60
100%	98%	53%

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Reason for Request: The Applicant reports that examination of 100% of the Code-required volume is limited due to the nozzle-to-pressurizer configuration. The Applicant also reports that these welds have received the required ASME Code Section III fabrication examinations.

Staff Evaluation: The staff has reviewed the Applicant's submittal, which included a listing of the nozzles for which relief is being requested, the nozzle design, the Code-requirement from which relief is being requested, and a sketch showing the scanning limitations which limit the examination.

Based on the above review, the staff has concluded that the limited Section XI volumetric examination and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

However, for future ISI examinations, the Applicant should monitor the development of new or improved examination techniques. As improvements in these areas are achieved, the staff will require that these enhanced techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

D. Relief Request, Examination Category B-B, Item B2.40, Steam Generator Tubesheet-to-Head Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-B, Item B2.40 requires a 100% volumetric examination of Steam Generator tubesheet-to-head welds as defined by Figure IWB-2500-6.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Steam Generator welds:

		Percent Not Examined		
Steam Generator	Weld No.	0	45	60
2RCS-SG21A	1	1.5%	.3%	1.5%
2RCS-SG21B	1	1.5%	.3%	1.5%
2RCS-SG21C	1	1.7%	.3%	1.5%

Reason for Request: The Applicant reports that ultrasonic examination was restricted by welded pads adjacent to the subject welds. The Applicant also reported that the subject welds received the ASME Code Section III fabrication examinations.

Staff Evaluation: Based on review of the Applicant's submittal, the staff has concluded that a significant percentage (greater than 98%) of the Code-required examination has been performed and that the Steam Generators would have to be redesigned in order to complete the remainder. The staff concludes that the Code-required volumetric examination has essentially been completed, that this examination and the Section III fabrication examinations provide an acceptable level of preservice structural integrity, and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

E. Relief Request, Examination Category B-D, Item B3.140, Steam Generator Nozzle Inside Radius Sections

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Item B3.140 requires a 100% volumetric examination of Steam Generator nozzle inside radius sections as defined by Figure IWB-2500-7.

Code Relief Request: Relief is requested from performing the Code-required volumetric examination of the following Steam Generator nozzle inner radii:

Nozzles 1A, 2A, and 3A (hot legs)
Nozzles 1B, 2B, and 3B (cold legs)

Reason for Request: The Applicant states that the configuration of the nozzle to steam generator at the inner radius section is such that 100% interrogation by ultrasonic techniques is not possible for the following reasons: A) Constantly changing geometry on the outside surface makes it difficult to correlate search unit position with the inside surface sound beam impingement point. B) Thickness variations in nozzle sections would require unique calibration standards capable of encompassing the metal path required to reach the inner radius sensitivity reflectors representative of anticipated critical flaw size. C) As-welded clad surface and nozzle dam retaining rings cause spurious and confusing reflectors. D) Present UT methodology does not permit meaningful examination of required volume from the external surface.

The Applicant proposes, as an alternative, a visual examination of the nozzle inside radius sections utilizing remote or direct video techniques.

Staff Evaluation: The staff has reviewed the Applicant's submittal and determined that, although the Applicant may not have confidence in this examination for determining the condition of the subject components, it has not supplied enough information to establish that the Code-required volumetric examination is impractical. The Applicant has not provided dimensional sketches that show that the inner radius volumetric examinations are impossible to perform and that total relief is justified.

Although the limiting features reported above may preclude a 100% examination, examination of a significant percentage of the inner radius areas may be possible. Therefore, it is not unreasonable to require that the Applicant comply with the requirements of Section XI until the Applicant provides enough justification to support the determination of impracticality.

F. Relief Request, Examination Category B-J, Items B9.11, B9.21, B9.31, and B9.40, Pressure Retaining Welds in Class 1 Piping

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Item B9.11 requires a 100% surface and volumetric examination of circumferential welds in piping 4 inch and greater nominal pipe size (NPS) as defined by Figure IWB-2500-8; Item B9.21 requires a 100% surface examination of circumferential welds in piping less than 4 inch NPS as defined by Figure IWB-2500-8; Item B9.31 requires a 100% surface and volumetric examination of branch pipe connection welds 4 inch and greater NPS as defined by Figures IWB-2500-9, -10, and -11; Item B9.40 requires a 100% surface examination of socket welds as defined by Figure IWB-2500-8.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume or surface on the following Class 1 pressure retaining piping welds:

Relief Requested for Volumetric Examinations

Weld Number	% of Exam Completed
2RCS-080-F01	99%
2RCS-107-2F	80%
2RCS-215-1-C	80%
2SIS-271-F503	45%
2SIS-287-F03	75%
2SIS-288-F02	75%
2RCS-84-F3	95%
2RCS-06-2-2	50%
2RCS-03-2-2	50%
2RCS-09-2-2	50%
2RCS-01-1A-1	50%
2RCS-01-1A-2	50%
2RCS-03-2-3	50%
2RCS-06-2-3	50%
2RCS-09-2-3	50%
2RCS-07-1-2	50%
2RCS-07-1-1	50%
2RCS-003-F1	75%
2RCS-006-F1	75%
2RCS-009-F1	75%
2RCS-009-F4	60%
2RCS-006-F4	60%

Relief Requested for Volumetric Examinations
(Continued)

Weld Number	% of Exam Completed
2RCS-003-F4	60%
2RCS-1-F3	83%
2RCS-004-F3	85%
2RCS-7-F3	83%
2RCS-004-F2	> 85%
2RCS-7-F2	85%
2RCS-1-F2	85%
2RCS-1-F4	50%
2RCS-4-F4	50%
2RCS-7-F4	50%
2RCS-003-F3	83%
2RCS-006-F3	> 85%
2RCS-009-F3	83%
2RCS-003-F2	83%
2RCS-006-F2	85%
2RCS-009-F2	83%
2RCS-005-F1	50%
2RCS-002-F1	50%
2RCS-8-F1	50%
2RCS-2-F3	97%
2RCS-5-F3	97%
2RCS-08-F3	97%

Relief Requested for Surface Examinations

Weld Number	% of Exam Completed
2RCS-056-2A	95%
2RCS-056-F03	95%
2CHS-142-11B-D	80%

Reason for Request: The Applicant states that the above welds cannot receive the complete Code-required examination due to restrictions caused by rigid restraints, welded lugs, support plates, and weld configurations such as pipe-to-branch connections, nozzle-to-pipe, pipe-to-fitting, or pipe-to-valve welds. As identified above, the Code examinations were performed to the maximum extent practicable.

Staff Evaluation: The staff has reviewed the above information and notes that a significant percentage of the Code-required volumetric examination was completed and that complete examinations which met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as these partially inspected welds. Since the partially inspected welds will see the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained.

Based on the above, the staff has concluded that the limited Section XI examinations, in conjunction with the Code Section III examinations performed during fabrication, provide an acceptable level of assurance of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

G. Relief Request, Examination Category C-A, Items C1.10, C1.20, and C1.30, Pressure Retaining Weld in Class 2 Pressure Vessels

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-A, Items C1.10 and C1.20 require a 100% volumetric examination of Class 2 pressure vessel circumferential shell and head welds as defined by Figure IWC-2500-1. Item C1.30 requires a 100% volumetric examination of Class 2 pressure vessel tubesheet-to-shell welds as defined by Figure IWC-2500-2.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Class 2 pressure vessel welds:

Steam Generator 2RCS-SG21A

Weld No.	% Not Examined			Reason for Limited Exam
	0	45	60	
2	2%		3%	Handholes, branch connections, and welded pads
3	.25%	.25%	.25%	Welded pads
5		.5%	10%	Welded pads
6			<.5%	Welded pads and branch connection
8		.15%	8.5%	Welded pads and Head-to-Shell configuration

Seal Water Return Filter 2CHS-FLT23

Weld No.	% Not Examined			Reason for Limited Exam
	0	45	60	
1		<1%		Flange-to-Shell configuration

Seal Water Injection Filter 2CHS-FLT24A

Weld No.	% Not Examined			Reason for Limited Exam
	0	45	60	
1	5%			Flange-to-Shell configuration
2	25%	25%		2" nozzle and 4 welded supports

Volume Control Tank 2CHS-TK22

Weld No.	% Not Examined 0	45	60	Reason for Limited Exam
1	5.5%	5.5%		2 welded lifting lugs
2	11.7%	12%		4 welded lifting lugs and manway cover

Recirculation Spray Cooler 2RSS-E21A

Weld No.	% Not Examined 0	45	60	Reason for Limited Exam
1	8.4%	8.4%		2 welded supports and 3/4" bolt
11		11.3%		Welded support, 3/4" bolt, and 3" nozzle

Regenerative Heat Exchanger 2CHS-E23

Weld No.	% Not Examined 0	45	60	Reason for Limited Exam
1		9%		Two 3" nozzles
2		36%		Welded support and two 3" nozzles
3		33%		Welded support
4		3.5%		One 3" nozzle
5		7%		Two 3" nozzles
6		38%		Welded support and two 3" nozzles
7		38%		Welded support
8		3.5%		One 3" nozzle
9		7%		Two 3" nozzles
10		36%		Welded support and two 3" nozzles
11		36%		Welded support, three welded lugs, and one 3" nozzle
12		3.5%		One 3" nozzle

Non-Regenerative Letdown Heat Exchanger 2CHS-E22

Weld No.	% Not Examined 0	45	60	Reason for Limited Exam
1		59%		Flange-to-shell configuration and two welded supports

Residual Heat Exchanger 2RHS-E21A

Weld No.	% Not Examined 0	45	60	Reason for Limited Exam
1	100%	3%		100% 0° restriction from flange side of the weld and 3% 45° restriction due to welded support
2	86% 35%	86%(wall side) 35%(head side)		Two 10" nozzles, concrete wall, and support base plate

Excess Letdown Heat Exchanger 2CHS-E24

Weld No.	% Not Examined 0	 45	 60	Reason for Limited Exam
1		5%		Four 1" branch connections and flange-to-shell configuration

Relief is also requested from performing 100% of the Code-required volumetric examination of the following Class 2 pressure vessel welds:

Reactor Coolant Filter 2CHS-FLT22

Weld No.	
1, 2, & 3	The Applicant states that, due to material thickness (.188") of the Reactor Coolant Filter, ultrasonic examination is not feasible.

Seal Water Heat Exchanger 2CHS-E21

Weld No.	
1 & 2	The Applicant states that, due to the changing material thicknesses of the shell (.178") to head (1.875") weld, ultrasonic examination is not feasible.

Reason for Request: The specific reasons for the limited volumetric examinations and the extent of the limitations are provided in the above table. For the above welds receiving a limited volumetric examination, the Applicant has stated that the Code-required volumetric examination is being done to the maximum extent possible.

The Applicant has committed to a 100% surface examination in lieu of the volumetric examination for the Reactor Coolant Filter and the Seal Water Heat Exchanger.

Staff Evaluation: The staff has reviewed the Applicant's submittal, which included a listing of the welds for which relief is being requested, the weld design, the Code requirement from which relief is being requested, the specific obstruction which limits the examination, and sketches, drawings, or photographs showing specific obstructions.

Based on the above review, the staff has concluded that a significant percentage of the Code-required examination has been performed on most of the welds (except the welds on the Reactor Coolant Filter and the Seal Water Heat Exchanger) and that the subject Class 2 vessels would have to be redesigned in order to complete the remainder. The staff concludes that the limited Section XI volumetric examination and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested for all of the above subject welds except those of the Reactor Coolant Filter and the Seal Water Heat Exchanger.

Reactor Coolant Filter and Seal Water Heat Exchanger: Based on the review of the above information, supplied by the Applicant, with regards to the welds on the Reactor Coolant Filter and the Seal Water Heat Exchanger, it is suggested that the Applicant perform the Code-required volumetric examination using the guidance provided in Code Case N-435-1. Therefore, until the Applicant has demonstrated that the Code-required volumetric examination is impractical or that the examination would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety, relief is denied.

H. Relief Request, Examination Category C-B, Items C2.21 and C2.22, Class 2 Nozzle-to-Shell Welds and Nozzle Inside Radius Sections

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-B, Item C2.21 requires a 100% surface and volumetric examination of Class 2 nozzle-to-shell (or head) welds, in vessels with greater than 1/2 inch nominal wall thicknesses. Item C2.22 requires a 100% volumetric examination of the nozzle's inside radius section. These examinations are to be as defined by Figure IWC-2500-4.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Class 2 nozzles:

Steam Generator 2RCS-SG21A
Weld No.
9
9IR
10IR

Residual Heat Exchanger 2RHS-E21A
Weld No.
3
4

Reason for Request: Steam Generator: Volumetric examination of Weld 9 can only be performed from one side of the weld due to nozzle configuration. Inside radius section 9IR can only receive 10% of the Code-required examination utilizing a 45° search unit and 80% of the Code-required examination utilizing a 60° search unit due to sharp nozzle O.D. curvature and surface roughness. Volumetric examination of the inside radius section 10IR cannot be performed because of excessive lift-off and beam redirection caused by curvature and surface roughness of the nozzle O.D. contour.

Residual Heat Exchanger: Volumetric examination is restricted by two support bore plates. 20% of the Code-required volume of Welds 3 and 4 cannot be examined utilizing a 45° search unit from the vessel side.

The Applicant reported that the Code-required volumetric examination was completed on all accessible portions of the subject nozzles on both the Steam Generator and the Residual Heat Exchanger.

Staff Evaluation: The staff has reviewed the Applicant's submittal, which included a listing of the nozzles for which relief is being requested, the nozzle design, the Code requirement from which relief is being requested, and a sketch showing the scanning limitations of the examinations.

Based on the above review, the staff has concluded that the limited Section XI volumetric examination (where possible) and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

However, for future ISI examinations, the Applicant should monitor the development of new or improved examination techniques. As improvements in these areas are achieved, the staff will require that these enhanced techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

I. Relief Request, Examination Category C-C, Item C3.70, Charging Pump Integrally Welded Supports

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-C, Item C3.70 requires a 100% surface examination of integrally welded attachments on Class 2 pumps as defined by Figure IWC-2500-5.

Code Relief Request: Relief is requested from examining 100% of the Code-required surface on Charging Pump 2CHS-P21A, Welded Support Nos. 1WS and 2WS.

Reason for Request: Some areas of the subject welded supports are inaccessible for surface examination as they are located under the Charging Pump.

Staff Evaluation: The staff has reviewed the Applicant's submittal and concluded that a significant percentage of the Code-required examination has been performed on the subject welds and that the supports would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI examination provides an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

J. Relief Request, Examination Category C-F-1, Item C5.11, Pressure Retaining Welds in Austenitic Stainless Steel or High Alloy Piping, and Examination Category C-F-2, Items C5.51 and C5.52, Pressure Retaining Welds in Carbon and Low Alloy Steel Piping

Code Requirement: Section XI (83W83), Table IWC-2500-1, Examination Categories C-F-1 and C-F-2, Items C5.11, C5.51 and C5.52 all require a 100% surface and volumetric examination of Class 2 pressure retaining piping welds in piping greater than 4 inch nominal pipe size (NPS) and with 3/8 inch or greater nominal wall thickness, as defined by Figure IWC-2500-7.

Code Relief Request: Relief is requested from examining 100% of the Code-required volume on the following Class 2 pressure retaining piping welds:

Weld Number	% of Exam Completed
2MSS-035-6-A	99%
2MSS-035-L05	85%
2MSS-107-F500	> 95%
2MSS-107-1B	> 95%
2MSS-169-F04	> 98%
2MSS-1-1A1-A	> 75%
2MSS-106-F500	> 95%
2MSS-106-1B	> 95%
2MSS-170-F02	99%
2MSS-170-F04	> 98%
2MSS-2-1A-A	83% *
2MSS-105-F500	> 95%
2MSS-105-1B	> 95%
2MSS-3-1A-B	65% *
2SVS-015-F13	95%
2SVS-014-F11	95%
2SVS-012-F08A	50%
2RHS-001-F08	75%
2SIS-018-1A-B	85%
2SIS 010-F501	83%

* Augmented ISI to protect against postulated piping failures

Reason for Request: The Applicant states that the subject welds cannot receive complete examination of the Code-required volume due to physical obstructions such as welded branch lines, proximity of adjacent components, and welded attachments. The Code-required volumetric examinations were performed to the maximum extent practicable.

Staff Evaluation: The staff has reviewed the above information and noted that a significant percentage of the Code-required volumetric examination was completed and that complete examinations which met the requirements of ASME Code Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as these partially inspected welds. Since the partially inspected welds will see the same operating and environmental conditions as the inspected welds, a reasonable assurance of the structural integrity of the welds for which relief is requested has been attained.

The staff has concluded that the limited Section XI volumetric examinations and the full Section XI surface examination provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

K. Relief Request, Examination Category C-C, Item C3.40, Integrally Welded Attachments on Class 2 Piping

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-C, Item C3.40 requires a 100% surface examination of integrally welded attachments whose base material design thickness is 3/4 inch or greater on Class 2 piping as defined by Figure IWC-2500-5.

Code Relief Request: Relief is requested from examining 100% of the Code-required surface on the following integrally welded attachments on Class 2 piping:

Weld Number	% of Exam Completed
2SIS-009-F802	85%
2SIS-009-F803	85%
2SIS-009-F804	85%
2SIS-009-F805	85%
2SIS-009-F806	85%
2SIS-009-F807	85%
2SIS-009-F808	85%
2SIS-009-F809	85%
2SIS-009-F506	85%
2SIS-009-F507	85%

Weld Number	% of Exam Completed
(Continued)	
2SIS-009-F508	85%
2SIS-009-F509	85%
2SIS-009-F510	85%
2SIS-009-F511	85%
2SIS-009-F512	85%
2SIS-009-F513	85%

Reason for Request: The Applicant reports that all of the above integrally welded attachments have a box beam (part of the support) obstructing all lugs, thus preventing surface examination of approximately 15% of the Code-required surface area. The Code-required surface examination was performed to the maximum extent practicable.

Staff Evaluation: The staff has reviewed the above information and notes that a significant percentage (approximately 85%) of the Code-required surface examination was completed. The staff has concluded that the limited Section XI surface examination, in conjunction with the Code Section III examinations performed during fabrication, provides an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, relief is granted as requested.

IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. In all cases except the request for relief from the volumetric examination of the Steam Generator nozzle inside radius sections (Section III.E above) and the volumetric examination of the Reactor Coolant Filter and Seal Water Heat Exchanger welds (Section III.G above), the Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety, or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing Beaver Valley Power Station - Unit 2 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are: the pressurizer, the steam generators, and a number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

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NRC FORM 335
(2-84)
NRCM 1102,
3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

SEE INSTRUCTIONS ON THE REVERSE

1 REPORT NUMBER (Assigned by TIDC, add Vol. No., if any)
NUREG-1057
Supplement No. 5

2 TITLE AND SUBTITLE
Safety Evaluation Report Related to the Operation of
Beaver Valley Power Station, Unit 2

3 LEAVE BLANK

4 DATE REPORT COMPLETED
MONTH: May
YEAR: 1987

5 AUTHOR(S)

6 DATE REPORT ISSUED
MONTH: May
YEAR: 1987

7 PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

8 PROJECT/TASK/WORK UNIT NUMBER

9 FIN OR GRANT NUMBER

10 SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Same as 7. above

11a TYPE OF REPORT

b PERIOD COVERED (Inclusive dates)

12 SUPPLEMENTARY NOTES
Docket No. 50-412

13 ABSTRACT (200 words or less)

Supplement No. 5 to the Safety Evaluation Report for the application filed by Duquesne Light Company, et al., for license to operate the Beaver Valley Power Station, Unit 2 (Docket No. 50-412), located in Beaver County, Pennsylvania, has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. The purpose of this supplement is to update the Safety Evaluation of (1) additional information submitted by the applicants since Supplement No. 4 was issued, and (2) matters that the staff had under review when Supplement No. 4 was issued.

14 DOCUMENT ANALYSIS a. KEYWORDS/DESCRIPTORS

b. IDENTIFIERS/OPEN-ENDED TERMS

15 AVAILABILITY STATEMENT
Unlimited

16 SECURITY CLASSIFICATION
(This page)
Unclassified
(This report)
Unclassified

17 NUMBER OF PAGES

18 PRICE

☆ U.S. GOVERNMENT PRINTING OFFICE:1987-181-682:60110

163